FOCUS ENERGY TRUST

STRENGTH. PERFORMANCE. SUSTAINABILITY.

2004 ANNUAL REPORT

NOTICE OF ANNUAL GENERAL MEETING

The Annual General and Special Meeting of Unitholders will be held at 3:00 p.m. on Tuesday, May 17, 2005 in the Nakiska Room at the Westin Hotel, 320 – 4th Avenue S.W., Calgary, Alberta.

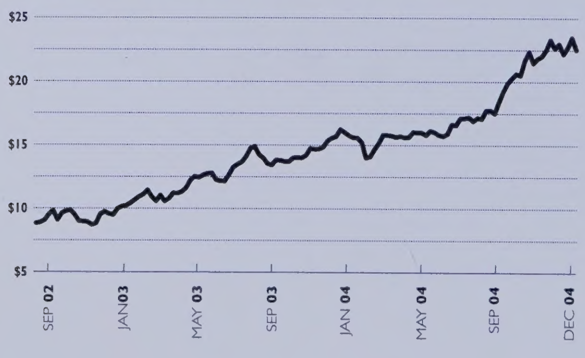
All Unitholders are invited to attend.

FOCUS ENERGY TRUST is a natural gas weighted energy trust. Focus is committed to maintaining its emphasis on operating high-quality oil and gas properties, delivering consistent distributions to Unitholders, and ensuring financial strength and sustainability.

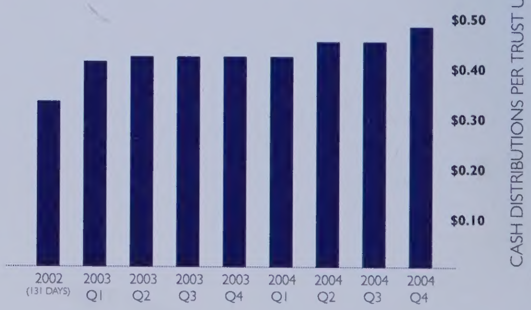
Focus Energy Trust Units trade on the TSX under the symbol **FET.UN**, and the Exchangeable Shares of FET Resources Ltd. trade on the TSX under the symbol **FTX**.

Production of natural gas and light oil is approximately 10,000 BOE/d and is produced from six main areas in British Columbia and Alberta. Production is weighted 73% to natural gas, and Focus operates approximately 87% of its production.

FET-UN EQUITY



FET-UN DISTRIBUTIONS PER QUARTER



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FORWARD-LOOKING INFORMATION

Certain information set forth in this document, including management's assessment of Focus' future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond Focus' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Focus' actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits Focus will derive therefrom. Focus disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Readers are cautioned that net present value of reserves does not represent fair market value of reserves.

2004 HIGHLIGHTS

(000s OF DOLLARS, EXCEPT WHERE INDICATED)	Years Ended, December 31, 2004[1]	2003[2]	Change
FINANCIAL			
Oil and gas revenues, before transportation system charges and royalties	**$ 150,173**	$ 119,367	26%
Funds flow from operations[3]	**$ 89,567**	$ 65,808	36%
Per Total Unit[4]	**$ 2.49**	$ 2.16	16%
Cash distributions per Trust Unit			
Per Total Unit[5]	**$ 1.80**	$ 1.665	8%
Payout ratio (per-Unit basis)	**72%**	77%	(5)%
Net income[1]	**$ 59,628**	$ 41,446	44%
Per Unit[1]	**$ 1.66**	$ 1.36	22%
Capital expenditures and acquisitions	**$ 154,855**	$ 37,026	318%
Long-term debt plus working capital	**$ 81,158**	$ 24,641	229%
Total Trust Units - outstanding (000s)[6]	**37,223**	31,822	17%
Weighted average Total Trust Units (000s)[7]	**35,903**	30,493	18%
OPERATIONS			
Average daily production			
Crude oil (bbls/d)	**1,996**	2,354	(15)%
NGLs (bbls/d)	**669**	485	38%
Natural gas (mcf/d)	**42,706**	34,254	25%
Barrels of oil equivalent (@ 6:1)	**9,782**	8,548	14%
Average net product prices realized[8]			
Crude oil (CDN$/bbl)	**$ 40.43**	$ 40.74	(1)%
NGLs (CDN$/bbl)	**$ 43.73**	$ 34.24	28%
Natural gas (CDN$/mcf)	**$ 6.41**	$ 5.55	16%
Netback per BOE			
Revenue[8]	**$ 39.27**	$ 35.41	11%
Royalties, net of ARTC	**$ (9.52)**	$ (9.78)	(3)%
Production expenses	**$ (3.29)**	$ (3.39)	(3)%
Netback	**$ 26.46**	$ 22.24	19%
Wells drilled			
Gross	**24**	23	4%
Net	**14.6**	9.3	57%
Success rate	**96%**	96%	–
TRUST UNIT TRADING STATISTICS			
Unit prices			
High	**$ 21.39**	$ 15.30	
Low	**$ 12.90**	$ 10.05	
Close	**$ 19.97**	$ 15.00	33%
Daily average trading volume	**112,677**	87,848	28%
RESERVES			
Proved plus probable[9]			
Crude oil (mbbls)	**5,697**	6,498	(12)%
NGLs (mbbls)	**3,387**	2,037	66%
Natural gas (Mmcf)	**194,462**	126,360	54%
Barrels of oil equivalent (MBOE/d @ 6:1)	**41,495**	29,595	40%
Reserve life index of proved plus probable[10]	**10.6**	9.8	8%
Gas weighting of proved plus probable reserves	**78%**	71%	7%
Proved reserves/proved plus probable reserves	**76%**	77%	(1)%

(1) FINANCIAL RESULTS PREVIOUSLY REPORTED FOR THE FIRST THREE QUARTERS OF 2004 HAVE BEEN RESTATED FOR CHANGES IN ACCOUNTING POLICIES RELATED TO TRANSPORTATION SYSTEM CHARGES AS DESCRIBED IN NOTE 2 OF THE FINANCIAL STATEMENTS.

(2) FINANCIAL RESULTS FOR 2003 HAVE BEEN RESTATED FOR CHANGES IN ACCOUNTING POLICIES RELATED TO ASSET RETIREMENT OBLIGATIONS AND TRANSPORTATION SYSTEM CHARGES AS DESCRIBED IN NOTE 2 OF THE FINANCIAL STATEMENTS.

(3) FUNDS FLOW FROM OPERATIONS ("FUNDS FLOW" BEFORE CHANGES IN NON-CASH WORKING CAPITAL) IS USED BY MANAGEMENT TO ANALYZE OPERATING PERFORMANCE AND LEVERAGE. FUNDS FLOW, AS PRESENTED, DOES NOT HAVE ANY STANDARDIZED MEANING PRESCRIBED BY CANADIAN GAAP AND THEREFORE IT MAY NOT BE COMPARABLE WITH THE CALCULATION OF SIMILAR MEASURES OF OTHER ENTITIES. FUNDS FLOW, AS PRESENTED, IS NOT INTENDED TO REPRESENT OPERATING CASH FLOW OR OPERATING PROFITS FOR THE PERIOD NOR SHOULD IT BE VIEWED AS AN ALTERNATIVE TO CASH FLOW FROM OPERATING ACTIVITIES, NET EARNINGS OR OTHER MEASURES OF FINANCIAL PERFORMANCE CALCULATED IN ACCORDANCE WITH CANADIAN GAAP. ALL REFERENCES TO FUNDS FLOW THROUGHOUT THIS REPORT ARE BASED ON FUNDS FLOW FROM OPERATIONS BEFORE CHANGES IN NON-CASH WORKING CAPITAL.

(4) BASED ON THE WEIGHTED AVERAGE TOTAL UNITS OUTSTANDING FOR THE PERIOD (SEE NOTES 9 AND 10)

(5) BASED ON THE NUMBER OF TOTAL UNITS OUTSTANDING AT EACH CASH DISTRIBUTION DATE (SEE NOTE 9)

(6) TOTAL UNITS BEING TRUST UNITS AND EXCHANGEABLE SHARES CONVERTED AT THE EXCHANGE RATIO PREVAILING AT THE TIME. TOTAL TRUST UNITS AS PRESENTED DOES NOT HAVE ANY STANDARDIZED MEANING PRESCRIBED BY CANADIAN GAAP AND THEREFORE IT MAY NOT BE COMPARABLE WITH THE CALCULATION OF SIMILAR MEASURES OF OTHER ENTITIES. THE EXCHANGE RATIO WAS 1.27833 AT DECEMBER 31, 2004 AND 1.16718 AT DECEMBER 31, 2003.

(7) WEIGHTED AVERAGE TOTAL UNITS INCLUDING TRUST UNITS AND EXCHANGEABLE SHARES CONVERTED AT THE AVERAGE EXCHANGE RATIO (SEE NOTE 9)

(8) SETTLEMENTS FOR FINANCIAL HEDGING INSTRUMENTS NET OF TRANSPORTATION SYSTEM CHARGES

(9) RESERVE NUMBERS ARE TOTAL PROVED PLUS PROBABLE COMPANY WORKING INTEREST RESERVES BEFORE DEDUCTION OF ROYALTIES AND WITHOUT INCLUDING ANY ROYALTY INTERESTS AS DEFINED IN NATIONAL INSTRUMENT 51-101.

(10) RESERVE LIFE INDEX IS CALCULATED BY DIVIDING YEAR-END RESERVES BY THE FORWARD YEAR PRODUCTION ESTIMATE FROM THE RESERVE REPORTS.

MESSAGE TO THE UNITHOLDERS

2004 was a very successful year for Focus. We continued to execute our sustainable business model, add to our inventory of internal development opportunities and acquire strategic assets that are reflective of our tight gas initiatives. All the while, we enjoyed a strong commodity price environment that allowed us to increase distributions twice during the year.

HIGHLIGHTS

- Focus Units realized a 45 percent total annualized return in 2004. This makes Focus one of the top performing oil and gas trusts.
- Monthly distributions increased from $0.14 per Unit at the start of the year to $0.16 per Unit in the final quarter.
- Funds flow from operations per Unit increased 16 percent on a year-over-year basis.
- We successfully completed two strategic gas acquisitions. One of these acquisitions increased our presence at Tommy Lakes and the other provided us with a unique opportunity to grow a new tight gas core area with year-round access.
- Our capital program, including acquisitions, resulted in a 432 percent replacement of our annual production based on proved plus probable reserves.
- Year-over-year proved plus probable company gross reserves increased 40 percent. On a per-Unit basis, proved plus probable reserves increased by 20 percent .
- Net asset value per Unit increased 41 percent on a year-over-year basis, driven by significant increases in reserves per Unit and stronger commodity price forecasts.
- Our reserve life index on a proved plus probable basis increased from 9.8 years to 10.6 years.
- Proved plus probable, finding, development and acquisition costs of $11.38 per BOE (including future capital) represent a recycle ratio of 2.3.
- Operating costs of $3.29 per BOE decreased slightly from last year but have fundamentally held constant since the inception of the Trust two and a half years ago.
- Our sustainable business model allowed us to retire $2 million of debt after funding the Trust's distributions, capital and reclamation fund expenditures from cash flow.

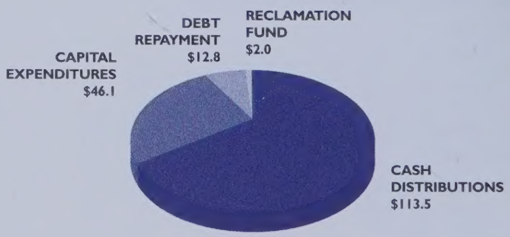
SUSTAINABILITY

When Focus was created in 2002, we set out to create a trust with a strong operational focus that utilized the drill bit to create value and that focused on sustainability.

We have accomplished what we set out to do. Our production has remained essentially constant on a per-Unit basis since inception as we have put retained cash flow to work on the Trust's asset base. In addition to fully funding our capital program, we have contributed $2 million to our reclamation fund and reduced debt by almost $13 million through this period.

Our ability to put cash flow to work on our lands is a function of our asset base and our technical team's talent in finding organic development opportunities. Over the last year we have strengthened our technical team with the further addition of geologists and engineers. The greater the replacement of production through organic drill bit activity, the greater the value creation for the Unitholder. Ultimately this leads to less reliance on the acquisition market and a greater control of our destiny.

FUNDS FLOW FROM OPERATIONS
Q3 2002 – Q4 2004 (MILLIONS)



TIGHT GAS ACQUISITIONS

As our history details, we are a selective acquirer of assets, focusing on large tight gas and oil accumulations where hydrocarbons are known to exist but where we either have not had the right price or technology, or a combination of both, to warrant economic development. Our two acquisitions in 2004 were both tight gas acquisitions, the first being the acquisition of a partner's interest at Tommy Lakes and the second being a private company active in southern Alberta on the edge of the 20 TCF Milk River, Medicine Hat and Second White Specks shallow gas fairway. Both of these assets exhibit typical tight gas characteristics of low decline rates and long reserve life index, as well as reserves that continue to grow over time as innovative technology and higher gas prices make it possible to coax more gas from these reservoirs. Approximately 75 percent of the Trust's reserves are in tight gas, low decline reservoirs. We believe these assets are key foundation elements to the Trust and we are committed to continuing to add this type of asset to our portfolio.

OUTLOOK

In 2005, our drilling and development activity will occur in all core areas with the majority of our $27 to $30 million capital program being spent at Tommy Lakes, Pouce Coupe, Medicine Hat and Loon Lake. Oilfield services have been at a premium for the last two quarters as industry activity levels reach new highs. We have adjusted our expectations accordingly, altered our execution parameters and continue to exercise prudence and caution. We are not going to spend more capital to do less. We anticipate that our capital program will result in average production of 10,000 to 10,500 BOE per day in 2005, and that our operating cost structure will remain essentially flat in the range of $3.40 to $3.50 per BOE.

Although we continue to evaluate both property and corporate acquisition opportunities, we have found little by way of public offering that fits our strategic requirements of large accumulations of tight gas or oil involving opportunities to put the drill bit to work. Accordingly, we have focused our attention on generating drilling ideas in and around our existing land base.

We anticipate that commodity prices and the Canadian/U.S. dollar exchange rate will continue to be volatile in 2005 as they were in 2004. As we have no crystal ball to provide clarity on future commodity prices, we will continue to focus our attention on the parts of the business in which we can have an impact, primarily the control of our operating costs and our capital reinvestment efficiencies. We remain committed to managing our distribution profile through our price protection program and conservative distribution policy in order that, ultimately, long-term returns to Unitholders are enhanced.

As we continue to enjoy an exceptional commodity price environment, be assured that your management team remains disciplined, focused and committed to increasing Unitholder value.

We would like to thank our Unitholders for investing in Focus and for their continued support.

We would also like to thank our Board of Directors for their continued guidance and our Focus team for their tireless efforts and continued enthusiasm.

On behalf of the Board,

Derek W. Evans
President and Chief Executive Officer

OPERATIONS REVIEW

All of Focus' producing properties are located in six main areas in Alberta and British Columbia. These include the natural gas dominated areas of Tommy Lakes, Kotcho-Cabin, Pouce Coupe, Sylvan Lake and Medicine Hat, and the oil dominated area of Red Earth.

In 2004, production of the Trust was weighted 73 percent to natural gas, with the remaining 27 percent consisting of light sweet crude and natural gas liquids. Our average working interest is approximately 71 percent, and we operate approximately 87 percent of our production.

TOMMY LAKES, NE BRITISH COLUMBIA

The Trust's largest single asset and main natural gas producing property is the Tommy Lakes area in northeastern British Columbia. The main producing zone at Tommy Lakes is the areally extensive blanket sand of the Triassic Halfway formation. Total pool original gas in place is in excess of 600 Bcf, of which approximately 27 percent has been produced to date. Although the reservoir is thick (more than 10 meters) and continuous, permeability is low, requiring all wells to be fracture stimulated to achieve stabilized rates of 600 to 800 mcf per day, with liquids recovered at 20 barrels per million cubic feet.

During 2004, Focus' gross production from the Tommy Lakes property averaged 29.4 Mmcf per day of natural gas and 569 bbls per day of natural gas liquids from 82 (78 net) wells. The base decline rate on the existing production is approximately 12 percent per year. Production at the property is compressed at four Focus-operated facilities and delivered into the Duke (Westcoast) system for further processing and delivery to markets.

On April 1, 2004 Focus acquired additional working interests at Tommy Lakes for $110 million. The acquisition increased our working interest in the western portion of the property to 100 percent and brought our overall average working interest up to approximately 95 percent. At December 31, 2004, Tommy Lakes represented approximately 65 percent of the Trust's reserves.

Subsequent to year-end, the Trust has successfully completed its 11-well (9.7 net) winter drilling program at Tommy Lakes. All 11 wells were cased and have been placed on production. This year's winter program set out to achieve four main objectives:

- further efficient infill development of the Halfway A Pool;
- selective Halfway step-out drilling to continue to extend the economic boundaries of the pool;
- testing of secondary zones such as the Bluesky and Doig;
- the implementation of well design and program execution initiatives designed to maximize our cost efficiencies.

The program was successful in achieving all of these objectives and the overall winter program at Tommy Lakes came in as per our expectations in terms of production rates and reserves. Based upon this continued success, Focus anticipates that the Tommy Lakes property will continue to be the main development area for the Trust, with at least two more years of similar sized development programs.

RED EARTH, ALBERTA

The Trust's light oil production is concentrated in the Red Earth area, within which the main producing properties are Golden, Loon Lake, Loon Lake North, Evi, and Kitty. In 2004 Focus' gross production from the Red Earth area averaged 1,913 bbls per day of 38° API light sweet crude. Approximately 44 percent of the Red Earth production is operated by Focus.

The majority of the Trust's development activity within the Red Earth area is concentrated at Loon Lake, which was acquired in June 2003. The main productive horizon at Loon Lake is the Slave Point G pool, which is a light oil reservoir under active waterflood. During 2004, the Trust drilled one well and recompleted two others into the Slave Point G pool, with encouraging results. Activities in 2005 will include further infill and step-out drilling as well as waterflood optimization.

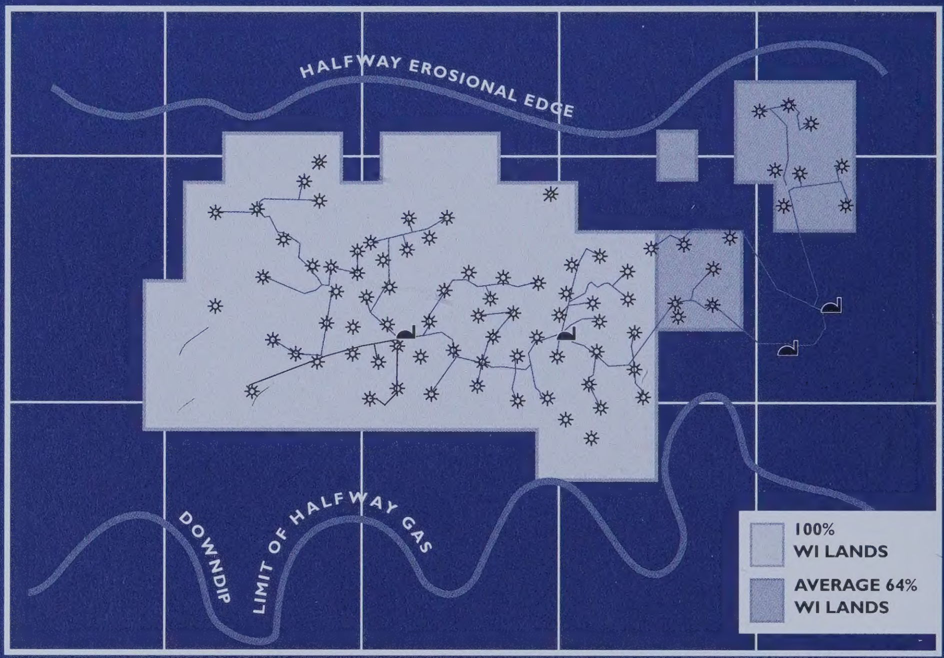
KOTCHO-CABIN, NE BRITISH COLUMBIA

At Kotcho and Cabin the Trust is producing from two sour high-pressure gas pools along a dolomitized reef edge in the Devonian Slave Point formation. Production from both properties is processed through 100 percent Focus-owned dehydration and water disposal facilities and delivered to the Duke (Westcoast) system.

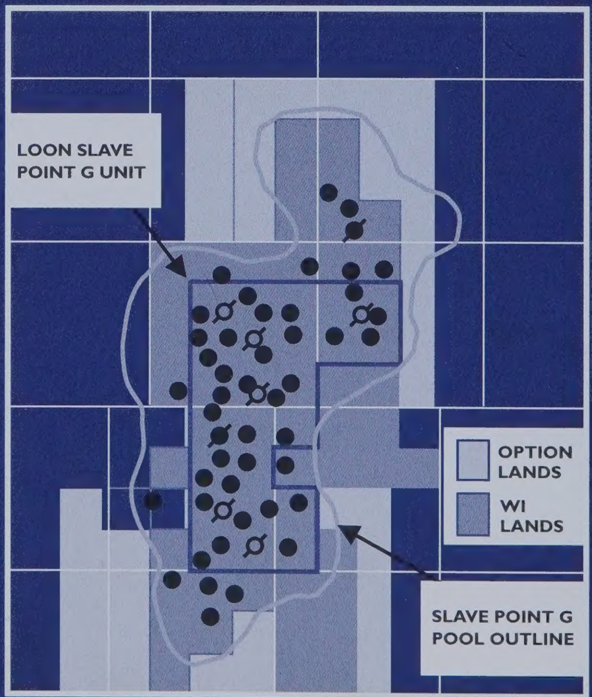
During 2004, Focus' gross production from this area averaged 8.1 Mmcf per day of natural gas. At Kotcho, volumes have decreased over the course of the year due to the onset of water production from the pool. Recently, volumes appear to be stabilizing, which is typical of offsetting Slave Point production. We continue to monitor production closely and

KOTCHO-CABIN
FORT NELSON
TOMMY LAKES
FORT ST. JOHN
RED EARTH
POUCE COUPE
British Columbia
Alberta
EDMONTON
SYLVAN LAKE
CALGARY
MEDICINE HAT
OIL PRODUCING
GAS PRODUCING

TOMMY LAKES



LOON LAKE



pursue the appropriate strategies to ensure that recovery from the pool is maximized. To this end, in the first quarter of 2005 the Trust will participate in the drilling of one well at Kotcho targeting the Slave Point.

POUCE COUPE, ALBERTA

At Pouce Coupe the Trust produces natural gas and associated NGLs from the Triassic Montney and Doig formations. Focus' gross production from this property in 2004 averaged 2.9 Mmcf per day of natural gas and 29 bbls per day of natural gas liquids. The majority of production is compressed at a 100 percent Focus-owned facility and then delivered to a third-party plant for further processing and delivery onto the TransCanada pipeline system.

Activity at Pouce Coupe has been concentrated on down-spacing within the Montney reservoir. Offsetting operators have commonly downspaced the Montney to four wells per section and in specific cases appear to be testing the economics of eight-well per section spacing. Focus drilled two wells into the Montney in late 2004 with good success, and anticipates drilling two more wells in 2005, which would bring the spacing on our lands to four wells per section.

SYLVAN LAKE, ALBERTA

Sylvan Lake is a multi-zone area which produces both gas and light oil from a number of formations ranging in depth from 400 to 2,200 meters. The primary producing zones are the Shunda, Pekisko, Lower Mannville, and Edmonton. In 2004, Focus' gross production from the area averaged 1.7 Mmcf per day of natural gas, and 154 bbls per day of oil and natural gas liquids. Production at Sylvan Lake is processed through the Focus-operated Sylvan Lake gas plant, in which the Trust holds an average working interest of 60 percent. The Trust owns excess capacity in this plant which generates material third party processing income.

In 2004 the Trust participated in the drilling of five (2.2 net) wells at Sylvan Lake, all targeting the Edmonton sand. All of these wells were successfully completed for gas, and the Trust anticipates a similar sized drilling program for 2005.

MEDICINE HAT, ALBERTA

Effective September 1, 2004, Focus acquired producing assets at Medicine Hat in southeastern Alberta for total consideration of $18.6 million. Effective October 1, 2004 the Trust acquired additional minor interests in the property for total consideration of $1.1 million. The property produces sweet natural gas from the Milk River, Medicine Hat and Second White Specks formations. Average working interest in the production is 90 percent, and the gas is compressed at two Focus-operated facilities. Focus' gross production from the Medicine Hat property averaged 1.9 Mmcf per day during the fourth quarter of 2004.

The Trust anticipates the first round of infill drilling on the Medicine Hat property will occur in early Q2 2005, depending on weather conditions and equipment availability. Pending the success of this program further development drilling is targeted for Q3 2005.

DRILLING

During 2004, the Trust participated in the drilling of 24 wells (14.6 net) with excellent drilling results and a success rate of 96 percent. The 2004 development program was strongly weighted towards natural gas with 96 percent of net wells and 84 percent of capital expenditures in the field directed towards gas targets. Focus was the operator of 20 of the 24 wells drilled in 2004.

Approximately two thirds of the Trust's capital expenditures for 2004 were invested at Tommy Lakes for the drilling of 16 (9.9 net) natural gas wells. Of the 16 wells, 11 were drilled and 10 of those tied in during the first quarter of 2004, and five were drilled in the fourth quarter of 2004 and tied in during the first quarter of 2005.

Additional activity in 2004 took place at Pouce Coupe with the drilling of two (2.0 net) natural gas wells in the Montney zone. At Sylvan Lake, the Trust participated in the drilling of five (2.2 net) Edmonton Sand gas wells. One Slave Point oil well (0.5 net) was drilled at Loon Lake, which is part of the Red Earth project area.

Drilling (Gross Wells)	2004 Oil	2004 Gas	2004 Abandoned	2004 Total	2003 Oil	2003 Gas	2003 Abandoned	2003 Total
Tommy Lakes	–	15	1	16	–	8	1	9
Red Earth	1	–	–	1	10	–	–	10
Pouce Coupe	–	2	–	2	–	2	–	2
Sylvan Lake	–	5	–	5	–	2	–	2
	1	22	1	24	10	12	1	23

Drilling (Net Wells)	2004 Oil	2004 Gas	2004 Abandoned	2004 Total	2003 Oil	2003 Gas	2003 Abandoned	2003 Total
Tommy Lakes	–	9.1	0.8	9.9	–	4.3	0.5	4.8
Red Earth	0.5	–	–	0.5	3.0	–	–	3.0
Pouce Coupe	–	2.0	–	2.0	–	1.3	–	1.3
Sylvan Lake	–	2.2	–	2.2	–	0.2	–	0.2
	0.5	13.3	0.8	14.6	3.0	5.8	0.5	9.3

UNDEVELOPED LAND

At December 31, 2004 Focus had undeveloped land of 26,876 net acres with an average working interest of 77 percent. Net undeveloped land is concentrated in Tommy Lakes (51 percent), Medicine Hat (21 percent), and Red Earth (16 percent).

Undeveloped Acres	December 31, 2004 Gross	December 31, 2004 Net
Alberta	16,729	11,645
British Columbia	18,027	15,231
	34,756	26,876

PRODUCTION

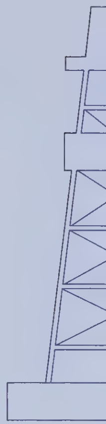
Focus had average production in 2004 of 9,782 BOE per day, with a weighting of 73 percent towards natural gas. Focus has had a very active drilling program at Tommy Lakes this past winter and 11 natural gas wells have been brought on stream in the first quarter of 2005. With the significance of winter drilling operations, Focus will continue to have its highest production volumes in the second quarter of the year as a result of flush production. For 2005, Focus is expecting to average between 10,000 and 10,500 BOE per day.

Production by Area	2004 Oil bbls/d	2004 Natural Gas mcf/d	2004 NGLs bbls/d	2004 BOE/d	2003 Oil bbls/d	2003 Natural Gas mcf/d	2003 NGLs bbls/d	2003 BOE/d
Tommy Lakes(1)	–	29,391	569	5,468	–	17,251	370	3,246
Red Earth	1,913	–	–	1,913	2,274	–	–	2,274
Kotcho-Cabin	–	8,156	–	1,359	–	11,978	–	1,996
Pouce Coupe	9	2,865	20	507	10	3,255	22	574
Sylvan Lake(2)	74	1,679	80	433	70	1,770	93	458
Medicine Hat(3)	–	615	–	102	–	–	–	–
	1,996	42,706	669	9,782	2,354	34,254	485	8,548

(1) INCLUDES APRIL 1, 2004 ACQUISITION OF ADDITIONAL INTERESTS AT TOMMY LAKES
(2) INCLUDES LANAWAY
(3) MEDICINE HAT PROPERTY WAS ACQUIRED EFFECTIVE SEPTEMBER 1, 2004.

Production by Quarter	2004 Q4	2004 Q3	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2	2003 Q1
Oil (bbls/d)	1,903	1,932	2,027	2,122	2,278	2,336	2,361	2,444
Natural gas (mcf/d)	43,080	44,903	50,913	31,902	32,475	33,593	36,815	34,158
NGL (bbls/d)	724	776	703	472	460	508	501	471
BOE/d	9,807	10,191	11,215	7,911	8,151	8,443	8,997	8,608

YEAR-END RESERVES REVIEW



YEAR-END RESERVES

Based on independent engineering evaluations conducted by Paddock Lindstrom and Associates Ltd. ("Paddock") and McDaniel and Associates Consultants Ltd. ("McDaniel") effective December 31, 2004, Focus had proved plus probable reserves of 41.5 MMBOE, an increase of 40 percent from the 29.6 MMBOE recorded at December 31, 2003. Year-end reserves were evaluated in accordance with National Instrument 51-101 ("NI 51-101").

Paddock and McDaniel evaluated 100 percent of the Trust's reserves. The portion of the evaluation conducted by Paddock represented 87 percent of the proved plus probable reserves and 84 percent of the associated future net revenue discounted at 10 percent. The remaining reserves and associated future net revenue were evaluated by McDaniel. The Paddock December 31, 2004 price forecast was used in the future net revenue determinations for both evaluations. The Trust's Reserves Committee, made up of independent and qualified directors of the Trust, has reviewed and approved the reports prepared by Paddock and McDaniel and other pertinent reserves data.

Proved developed producing reserves represent 54 percent of proved plus probable reserves, while total proved reserves represent 76 percent of total proved plus probable reserves. On a BOE basis, total proved plus probable reserves consist of 78 percent natural gas, 14 percent light crude oil and eight percent natural gas liquids. On a proved basis, technical revisions were positive 1.1 MMBOE, or approximately five percent of the opening balance. On a proved plus probable basis, technical revisions were positive 0.8 MMBOE, or three percent of the opening balance. In both cases, the revisions were due to performance changes on producing properties.

NET PRESENT VALUE OF FUTURE NET REVENUE

The estimated net present value of Focus' crude oil, natural gas and natural gas liquids reserves before tax was evaluated using Paddock's December 31, 2004 price forecast prior to provision for income taxes, interest, debt service charges and general and administrative expenses. At a 10 percent discount rate, the net present value of the Trust's proved plus probable reserves was $488 million. Proved producing and total proved reserves make up respectively 66 percent and 83 percent of the total proved plus probable value.

RESERVE LIFE INDEX

Focus' proved plus probable RLI at year-end 2004 increased to 10.6 years from 9.8 years at year-end 2003. The Trust's proved year-end 2004 RLI increased to 8.4 years from 7.7 years at year-end 2003. These RLIs are calculated using period-end reserves and forward-year forecast production from the reserves report.

RESERVE ADDITION COSTS

Under NI 51-101, the methodology to be used to calculate FD&A costs includes incorporating changes in future development capital ("FDC") required to bring the proved undeveloped and probable reserves to production. On a proved plus probable basis, Focus' 2004 reserve addition costs were $11.38 per BOE including acquisitions and divestitures or $15.99 per BOE excluding acquisitions and divestitures. On a total proved basis, 2004 reserve addition costs were $13.87 per BOE including acquisitions and divestitures or $18.40 per BOE excluding acquisitions and divestitures. At year-end, total estimated FDC was $47.5 million for proved reserves and $63.8 million for proved plus probable reserves.

RESERVES INFORMATION

The following cautionary statements are specifically required by NI 51-101.

1. It should not be assumed that the estimates of future net revenues presented in the tables represent the fair market value of the reserves. There is no assurance that the constant price and cost assumptions and forecast price and cost assumptions will be attained and variances could be material.
2. Disclosure provided herein in respect of BOE may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio of 6 mcf:1 bbl has been used in all cases in this disclosure. This BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
3. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.
4. Estimates of reserves and future net revenues for individual properties may not reflect the same confidence level as estimates of reserves and future net revenues for all properties due to the effects of aggregation.
5. In all cases, the F&D or FD&A cost is calculated by dividing the identified capital expenditures by the applicable reserves additions.

2004 RESERVES SUMMARY

Company Gross Reserves at December 31, 2004 (before deduction of royalties payable, not including royalties receivable) (based on Forecast Prices and Costs)	Light Crude Oil (mbbl)	Natural Gas (Mmcf)	NGLs (mbbl)	Oil Equivalent (MBOE)
Proved producing	3,306	102,229	1,909	22,253
Proved non-producing	195	10,883	114	2,123
Total proved developed	**3,501**	**113,112**	**2,023**	**24,376**
Proved undeveloped	736	35,258	578	7,191
Total proved	**4,237**	**148,370**	**2,601**	**31,567**
Probable additional	1,460	46,092	786	9,928
Total proved + probable	**5,697**	**194,462**	**3,387**	**41,495**

Company Net Reserves at December 31, 2004 (after deduction of royalties payable, including royalties receivable) (based on Forecast Prices and Costs)	Light Crude Oil (mbbl)	Natural Gas (Mmcf)	NGLs (mbbl)	Oil Equivalent (MBOE)
Proved producing	2,903	77,995	1,505	17,407
Proved non-producing	184	8,267	92	1,654
Total proved developed	**3,087**	**86,262**	**1,597**	**19,061**
Proved undeveloped	681	27,311	463	5,696
Total proved	**3,768**	**113,573**	**2,060**	**24,757**
Probable additional	1,288	35,002	626	7,748
Total proved + probable	**5,056**	**148,575**	**2,686**	**32,505**

NET ASSET VALUE

Net Asset Value (before tax) December 31, 2004

The following net asset value ("NAV") table shows what is commonly referred to as a "produce out" NAV calculation. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time.

NAV at December 31, 2004

($thousands except per-Unit amounts)	Paddock Price Forecast	Constant Price Forecast
Value of proved plus probable reserves discounted at 10%	487,795	520,608
Undeveloped lands	3,490	3,490
Net debt including working capital	(81,158)	(81,158)
Reclamation fund	1,923	1,923
Net abandonment, reclamation and salvage(1)	(300)	(179)
Net asset value	411,750	444,684
Total Units outstanding (thousands)	37,223	37,223
Per Total Unit	$11.06	$11.95

(1) IN ADDITION TO ABANDONMENT AND RECLAMATION LIABILITY ALREADY INCLUDED IN RESERVE REPORTS

Net asset value per Unit increased 41 percent on a year-over-year basis, driven by significant increases in reserves per Unit and stronger commodity price forecasts.

2004 RESERVE RECONCILIATION

Company Gross Reserves (before deduction of royalties payable, not including royalties receivable)	Light Crude Oil (mbbl)	Natural Gas (Mmcf)	NGLs (mbbl)	Oil Equivalent (MBOE)
TOTAL PROVED				
December 31, 2003	4,962	96,488	1,603	22,646
Discoveries	0	1,912	25	343
Extensions	29	0	0	29
Improved recovery	0	2,294	48	431
Technical revisions	(51)	5,752	171	1,078
Economic factors	0	0	0	0
Acquisitions	24	57,554	1,003	10,619
Dispositions	0	0	0	0
Production	(727)	(15,630)	(248)	(3,580)
December 31, 2004	**4,237**	**148,370**	**2,601**	**31,567**
PROBABLE				
December 31, 2003	1,536	29,872	434	6,949
Discoveries	0,	455	4	80
Extensions	15	0	0	15
Improved recovery	0	307	6	58
Technical revisions	(92)	(1,070)	35	(235)
Economic factors	0	0	0	0
Acquisitions	1	16,527	307	3,063
Dispositions	0	0	0	0
Production	0	0	0	0
December 31, 2004	**1,460**	**46,092**	**786**	**9,928**
PROVED PLUS PROBABLE				
December 31, 2003	6,498	126,360	2,037	29,595
Discoveries	0	2,367	28	423
Extensions	44	0	0	44
Improved recovery	0	2,602	55	488
Technical revisions	(143)	4,682	206	843
Economic factors	0	0	0	0
Acquisitions	25	74,081	1,310	13,682
Dispositions	0	0	0	0
Production	(727)	(15,630)	(248)	(3,580)
December 31, 2004	**5,697**	**194,462**	**3,387**	**41,495**

1) ALL RESERVES ARE BASED ON FORECAST PRICES AND COSTS.
2) NUMBERS MAY NOT ADD DUE TO ROUNDING.

NET PRESENT VALUE SUMMARY

Net Present Value of Future Net Revenue Before Income Taxes – Forecast Prices and Costs

(including ARTC) ($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	498,370	385,354	319,752	276,508	245,609
Proved non-producing	40,163	30,075	24,212	20,295	17,470
Total proved developed	**538,532**	**415,429**	**343,963**	**296,803**	**263,078**
Proved undeveloped	147,308	89,167	61,750	45,548	34,785
Total proved	**685,840**	**504,596**	**405,713**	**342,351**	**297,863**
Probable additional	226,249	125,062	82,082	59,331	45,559
Total proved + probable	**912,089**	**629,658**	**487,795**	**401,682**	**343,422**

NUMBERS MAY NOT ADD DUE TO ROUNDING.

December 31, 2004 Price Forecast – Paddock Lindstrom and Associates Ltd.

	WTI Crude Oil $US/bbl	Edmonton Light Crude Oil $CDN/bbl	Henry Hub Natural Gas $US/Mmbtu	AECO C Natural Gas $CDN/Mmbtu	Westcoast Station 2 Natural Gas $CDN/Mmbtu	Exchange Rate $US/$CDN
2005	42.00	50.22	6.30	6.78	6.76	0.82
2006	40.00	47.76	6.10	6.52	6.50	0.82
2007	37.50	44.69	5.90	6.26	6.24	0.82
2008	35.00	41.62	5.70	6.00	5.98	0.82
2009	33.00	39.16	5.50	5.73	5.71	0.82
2010	33.50	39.75	5.61	5.85	5.83	0.82
2011	34.00	40.34	5.72	5.96	5.94	0.82
2012	34.50	40.92	5.84	6.08	6.06	0.82
2013	35.00	41.51	5.95	6.21	6.19	0.82
2014	35.50	42.10	6.07	6.33	6.31	0.82
2015	36.00	42.68	6.19	6.46	6.44	0.82
2016	36.50	43.27	6.32	6.59	6.57	0.82
2017	37.00	43.85	6.44	6.72	6.70	0.82
2018	37.50	44.44	6.57	6.85	6.83	0.82
2019	38.00	45.02	6.70	6.99	6.97	0.82
Escalate thereafter at	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	0%/yr

Net Present Value of Future Net Revenue Before Income Taxes – Constant Prices and Costs

(including ARTC) ($ thousands)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	536,481	410,893	336,987	288,192	253,460
Proved non-producing	43,618	32,431	25,834	21,429	18,273
Total proved developed	**580,098**	**443,324**	**362,821**	**309,621**	**271,733**
Proved undeveloped	153,665	97,337	68,588	50,993	39,125
Total proved	**733,764**	**540,661**	**431,409**	**360,614**	**310,857**
Probable additional	231,875	133,550	89,199	64,933	49,965
Total proved + probable	**965,638**	**674,210**	**520,608**	**425,547**	**360,822**

NUMBERS MAY NOT ADD DUE TO ROUNDING.

Constant Prices at December 31, 2004	Edmonton Light Crude Oil $CDN/bbl	AECO C Natural Gas $CDN/Mmbtu	Westcoast Station 2 Natural Gas $CDN/Mmbtu
2005 and thereafter	47.25	6.78	6.27

FINDING AND DEVELOPMENT COSTS

Company Gross Reserves Excluding the Effect of Acquisitions and Dispositions[1]

	2004	2003	2002[2][3]	Three-Year Total
Capital expenditures – $M	**25,156**	16,589	39,535	81,280
Net change in future development capital – $M				
Proved	**9,469**	(2,506)	14,140	21,103
Proved plus probable	**3,599**	(921)	17,703	20,381
Total capital including change in future development capital – $M				
Proved	**34,625**	14,083	53,675	102,383
Proved plus probable	**28,755**	15,668	57,238	101,661
Reserve additions – MBOE				
Proved	**1,882**	(1,153)	6,894	7,623
Proved plus probable	**1,798**	2,143	7,912	11,853
Finding and development cost – $/BOE				
Proved	**$ 18.40**	n/a	$ 7.79	$ 13.43
Proved plus probable	**$ 15.99**	$ 7.31	$ 7.23	$ 8.58

(1) RESERVES ARE BASED ON FORECAST PRICES AND COSTS.
(2) INCLUDES ACTIVITIES OF STORM ENERGY INC. PRIOR TO THE PLAN OF ARRANGEMENT EFFECTIVE AUGUST 23, 2002.
(3) RESERVES AND COSTS FOR 2002 ARE PRESENTED ON AN ESTABLISHED BASIS (PROVED PLUS PROBABLE RISKED AT 50%).

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Company Gross Reserves Including the Effect of Acquisitions and Dispositions[1]

	2004	2003	2002[2][3]	Three-Year Total
Capital expenditures – $M	**154,825**	36,805	40,140	231,770
Net change in future development capital – $M				
Proved	**18,594**	(94)	14,140	32,640
Proved plus probable	**21,360**	1,579	17,703	40,642
Total capital including change in future development capital – $M				
Proved	**173,419**	36,711	54,280	264,410
Proved plus probable	**176,185**	38,384	57,843	272,412
Reserve additions – MBOE				
Proved	**12,501**	1,247	6,894	20,642
Proved plus probable	**15,480**	4,869	7,912	28,261
Finding and development cost – $/BOE				
Proved	**$ 13.87**	$ 29.44	$ 7.87	$ 12.81
Proved plus probable	**$ 11.38**	$ 7.88	$ 7.31	$ 9.64

(1) RESERVES ARE BASED ON FORECAST PRICES AND COSTS.
(2) INCLUDES ACTIVITIES OF STORM ENERGY INC. PRIOR TO THE PLAN OF ARRANGEMENT EFFECTIVE AUGUST 23, 2002.
(3) RESERVES AND COSTS FOR 2002 ARE PRESENTED ON AN ESTABLISHED BASIS (PROVED PLUS PROBABLE RISKED AT 50%).

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is a discussion and analysis of the operating and financial results of Focus for the three months and year ended December 31, 2004 compared with the prior year, as well as information and opinions concerning the Trust's future outlook based on currently available information. **This discussion is dated February 28, 2005 and should be read in conjunction with the Trust's audited consolidated financial statements for the years ended December 31, 2004 and 2003, together with accompanying notes.**

Throughout this Management's Discussion and Analysis, we use the term funds flow from operations ("funds flow" before changes in non-cash working capital). Funds flow is used by management to analyze operating performance and leverage. Funds flow, as presented, does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures of other entities. Funds flow, as presented, is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds flow throughout this report are based on funds flow from operations before changes in non-cash working capital.

Per barrel of oil equivalent ("BOE") amounts have been calculated using a conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl).

OVERALL 2004 PERFORMANCE

Performance in 2004 reflects the strong commodity price environment, the quality of our assets, and the execution of our business strategy. Focus' strategy is to surface value on our existing assets, maintain cost efficiencies, maintain financial strength and acquire quality assets. Production of the Trust increased 16 percent and proved plus probable reserves increased 40 percent through development programs at our key properties, and through two acquisitions of quality natural gas properties which have development potential.

The Trust continues to expand its operational focus, with a 50 percent increase in field expenditures, a 57 percent increase in net wells drilled, and the addition of a new core area at Medicine Hat. Natural gas continues to be the primary emphasis of the Trust. During the year, we completed two significant natural gas acquisitions, targeted natural gas with 23 of the 24 wells drilled, and increased natural gas reserves by 54 percent. Natural gas and the associated natural gas liquids represented 80 percent of 2004 production and 86 percent of year-end proved plus probable reserves.

Focus had strong financial performance during 2004 and maintained its financial strength. Funds from operations increased due to robust commodity prices, additional production volumes and maintaining operating efficiencies. The $89.6 million of funds from operations were used to fully fund field capital expenditures of $25.2 million, distributions of $61.4 million, reclamation fund contributions and actual abandonment and reclamation expenditures of $1.0 million, with the remaining $2.0 million applied to debt.

Funds flow from operations increased to $2.49 per Unit and cash distributions declared were $1.80 per Unit, with two distribution increases during the year. The distribution policy is aimed at achieving consistency of distributions and sustainability through balancing funds flow compared to distributions and capital programs.

OPERATIONS SUMMARY

	Three Months Ended December 31, 2004	Years Ended December 31, 2004	2003	Change
Average daily production				
Barrels of oil equivalent (@ 6:1)	**9,807**	**9,782**	8,548	14%
% Natural gas	**73%**	**73%**	67%	9%
Average product prices realized[1]				
Crude oil sales (CDN$/bbl)	**$ 56.33**	**$ 51.43**	$ 42.69	20%
Financial hedging settlements (CDN$/bbl)	**$ (15.05)**	**$ (11.01)**	$ (1.95)	464%
	$ 41.28	**$ 40.43**	$ 40.74	(1)%
NGLs (CDN$/bbl)	**$ 48.48**	**$ 43.73**	$ 34.24	28%
NGL price / Crude oil price	**86%**	**85%**	80%	6%
Natural gas sales (CDN$/mcf)	**$ 7.25**	**$ 7.02**	$ 6.96	1%
Transportation system charges	**$ (0.61)**	**$ (0.61)**	$ (0.60)	2%
Financial hedging settlements (CDN$/mcf)	**$ –**	**$ –**	$ (0.82)	(100)%
	$ 6.64	**$ 6.41**	$ 5.55	16%
Reference prices & differential to Focus price, net to transportation				
Crude oil (Edm. Light Price CDN$/bbl)	**$ 57.74**	**$ 52.62**	$ 42.89	23%
Differential (CDN$/bbl)	**$ (1.41)**	**$ (1.18)**	$ (0.20)	506%
Natural gas (AECO daily CDN$/mcf)	**$ 6.57**	**$ 6.55**	$ 6.70	(2)%
Differential (CDN$/mcf)	**$ 0.07**	**$ (0.14)**	$ (0.34)	(58)%
Barrels of oil equivalent (@6:1)	**$ 44.34**	**$ 42.93**	$ 41.08	5%
Differential (including NGLs vs crude oil)	**$ (0.60)**	**$ (1.42)**	$ (1.86)	(24)%
Production revenue before transportation system charges and hedging settlements ($thousands)				
Crude oil, before hedging settlements	**9,891**	**37,704**	36,694	3%
Financial hedging settlements	**(2,634)**	**(8,040)**	(1,678)	379%
NGLs	**3,233**	**10,715**	6,067	77%
Natural gas, before hedging settlements	**28,743**	**109,793**	87,153	26%
Financial hedging settlements	**–**	**–**	(10,221)	(100)%
Mark to market adjustment	**–**	**–**	1,353	(100)%
	39,233	**150,173**	119,367	26%
Funds flow per BOE				
Production revenue before transportation system charges and hedging settlements	**$ 46.40**	**$ 44.19**	$ 41.85	6%
Financial hedging settlements	**(2.92)**	**(2.25)**	(3.81)	(41)%
Transportation system charges	**(2.66)**	**(2.68)**	(2.62)	2%
Realized price[1]	**40.82**	**39.27**	35.41	11%
Royalties, net of ARTC	**9.36**	**(9.52)**	(9.78)	(3)%
Production expenses	**(3.76)**	**(3.29)**	(3.39)	(3)%
Field netback	**27.71**	**26.46**	22.24	19%
Facility income	**0.58**	**0.73**	0.84	(13)%
Interest income	**0.05**	**0.06**	0.02	212%
Technical Services Agreement	**–**	**–**	(0.67)	(100)%
General and administrative, cash portion	**(1.21)**	**(1.13)**	(0.81)	39%
Interest and financing and other	**(0.93)**	**(0.70)**	(0.44)	58%
Current and large corporations tax	**(0.44)**	**(0.40)**	(0.07)	452%
Funds flow from operations	**$ 25.76**	**$ 25.02**	$ 21.09	19%
Funds flow from operations/field netback	**93%**	**95%**	95%	0%
Royalty rate (before hedging settlements)	**19%**	**20%**	22%	(8)%

(1) NET OF SETTLEMENTS FOR FINANCIAL HEDGING INSTRUMENTS AND TRANSPORTATION SYSTEM CHARGES

Seasonality of Operations

Many of Focus' natural gas properties are in areas of British Columbia which are only accessible by road in the winter. This includes Tommy Lakes and Kotcho-Cabin. These areas represent approximately 70 percent of our production. The majority of the Trust's capital program is conducted at Tommy Lakes in the first and fourth quarters when winter conditions allow us to access the area. Capital expenditures at Tommy Lakes represented 64 percent of the total field capital expenditures during 2004, and 66 percent in 2003.

The winter access issue, especially for the Tommy Lakes winter development program, significantly impacts the operating results of Focus. This seasonality of operations and results is reflected in the following areas:

- Capital expenditures are highest in the first and fourth quarters of the year. The Tommy Lakes winter development program commences as soon as there is access and is completed as soon as possible.
- The natural gas wells at Tommy Lakes are brought on stream in February and March. Production volumes for natural gas and natural gas liquids are highest at the end of the first quarter and into the second quarter. These wells have strong flush production and then drop down to their stabilized production rate within 12 months.
- Higher production volumes during these initial months of flush production result in a corresponding increase in the revenue, royalties and operating expenses reported.
- Production expenses per BOE are the highest in the first and fourth quarters when these properties are accessible for maintenance and the restocking of supplies.
- As the operator of these properties, the Trust recovers general and administrative expenses from joint venture capital programs based on a percentage of the total capital program managed. As a result, most of the recovery of general and administrative expenses will be in the first and fourth quarters of the year.

Production

2004 Q4 compared with 2004 Q3:

- Overall production on a BOE basis during the fourth quarter declined 3.8 percent from the previous quarter. Oil volumes were generally held flat, and natural gas volumes were four percent lower.
- Natural gas volumes added through development activities were slowed in the fourth quarter due to issues associated with land access, weather and the availability of oilfield equipment. For the two wells drilled at Pouce Coupe during the second half of 2004, one well came on stream in late November 2004, and the other well is expected to come on stream in the first quarter of 2005.
- Production of natural gas in the fourth quarter of 2004 increased 32 percent compared to the same period of 2003. The composition of production is increasingly weighted towards natural gas, with 73 percent natural gas and another seven percent of natural gas liquids.
- The wells at Tommy Lakes from last winter's drilling program continued to transition from the flush production phase. Reduced production rates at Kotcho-Cabin were in line with expectations.

2004 compared with 2003:

- Overall average production was 14 percent higher in 2004 compared with 2003.
- A significant increase in natural gas and natural gas liquids production occurred as a result of the 2004 acquisition of additional interests at Tommy Lakes in April. Production at Tommy Lakes represented 59 percent of overall production in the fourth quarter of 2004.
- Additional natural gas volumes were added in September as the Trust acquired a new core property at Medicine Hat.
- Focus continued to replace production volumes through successful drilling programs at Tommy Lakes, Pouce Coupe and Loon Lake.

- The production pattern for 2003 and 2004 is consistent with higher volumes of natural gas and NGLs peaking in the second quarter. This pattern is expected to continue for 2005 as the 2004-2005 winter drilling program at Tommy Lakes commenced in December 2004, and the new production will come on stream late in the first quarter of 2005.
- The majority of our oil properties have experienced natural declines in production rates. Capital expenditures for the oil properties have been directed towards our operated properties at Loon Lake and Golden.

Pricing and Price Risk Management

Natural Gas

- The net realized price for the fourth quarter of 2004 of $6.64 per mcf is $0.07 higher than the AECO daily reference price of $6.57 per mcf. This differential for the fourth quarter of 2004 is largely due to the forward physical sales contracts for natural gas being higher than the AECO daily reference price. Generally, Focus has a negative differential on natural gas of approximately $0.35 to $0.40 per mcf versus the AECO reference price resulting from the deductions to the delivery point for transportation system charges in British Columbia being only partially offset by the higher heat content of the natural gas.
- The net natural gas price realized by Focus in 2004 of $6.41 per mcf increased 16 percent from the $5.55 per mcf realized in 2003. During 2004 the net realized price achieved by Focus was $0.14 per mcf off of the AECO daily reference price. For 2003 the difference was $1.15 per mcf due to financial hedging costs and a wider differential.
- There were no settlements of financial instruments for natural gas in 2004. Price protection and stability in 2004 has been achieved through the use of forward physical sales contracts. Focus put price protection on 53 percent of natural gas volumes during 2004. The average natural gas price under these contracts was $7.13 per mcf, compared with the AECO reference price of $6.55 per mcf. Production income for 2003 included a hedging cost of $8.9 million for financial instruments associated with natural gas.

Crude Oil

- The price realized by Focus for crude oil, after settlement of financial hedges, was $41.28 per barrel for the fourth quarter of 2004 versus $37.20 for the comparable period in 2003.
- The net realized price of crude oil for Focus was relatively flat through 2003 and 2004 due to price protection in place.
- With continued strong oil prices in 2004, there was a hedging cost of $2.6 million or $15.05 per barrel, for the fourth quarter of 2004, and a hedging cost of $8.0 million or $11.01 per barrel for 2004. The hedging arrangements in place for 2004 expired on December 31, 2004 and the financial hedging arrangements for 2005 are shown in the table below.

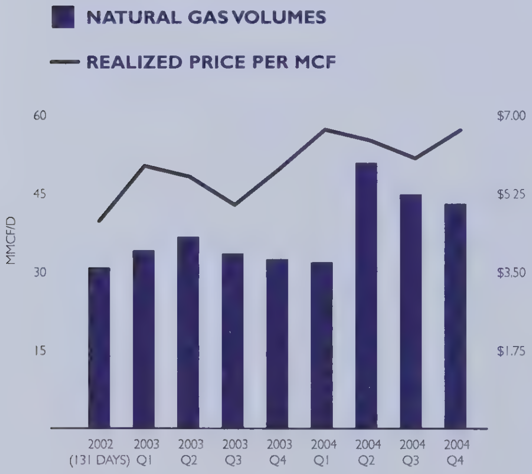
Price Protection		2005				2006
(volume and reference price)		Q1	Q2	Q3	Q4	Q1
Natural gas	Mmcf/d	30.0	22.6	22.6	15.7	12.2
	CDN$/mcf	$ 8.35	$ 7.65	$ 7.65	$ 8.08	$ 8.49
Crude oil	bbls/d	1,200	1,200	1,200	800	–
	CDN$/bbl	$ 50.37	$ 50.37	$ 50.70	$ 49.56	–

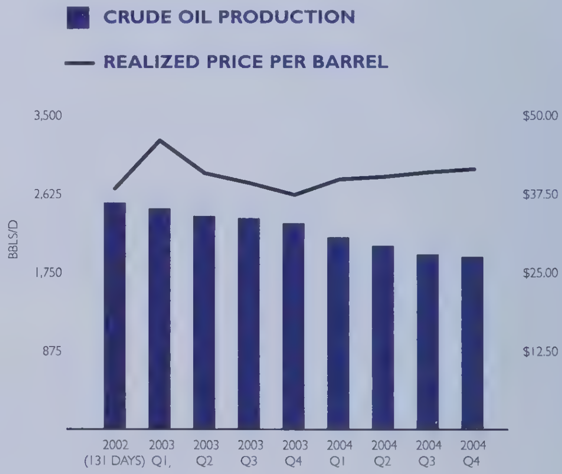
NOTE THAT THE PRICE PROTECTED WITH FINANCIAL INSTRUMENTS IS THE SWAP PRICE OR THE FLOOR OF A CONTRACT.

A full description of the outstanding financial instruments and physical sales contracts and their estimated mark to market values is contained in Notes 12 and 13 of the financial statements.

Production Revenue

- The results for 2004 and 2003 have been restated to present transportation system charges as a separate expense on the income statements. Previously, the transportation system charges were netted against production revenue.
- Production revenue for the three months ended December 31, 2004 was $39.2 million, consisting of 73 percent natural gas sales, 19 percent crude oil sales, and eight percent sales of natural gas liquids. Focus has increased its weighting of volumes to natural gas and natural gas liquids with the acquisitions and through development programs which primarily target natural gas opportunities. Production revenue for the fourth quarter of 2004 was $1.2 million higher than the third quarter of 2004 due to a seven percent increase in production revenue per BOE offsetting a four percent decrease in production.
- Production revenue for 2004 increased 26 percent to $150 million. Compared with 2003, there was a 14 percent increase in average daily production and an 11 percent increase in revenue per BOE.





Production Expenses

	2004				2003			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Production expenses per BOE	**$ 3.76**	**$ 3.31**	**$ 2.52**	**$ 3.78**	$ 3.70	$ 3.51	$ 3.04	$ 3.36

- The pattern of production expenses being highest in the first and fourth quarters and lowest in the second and third quarters is consistent with the nature of our operations and the results of 2003.
- Production expenses for 2004 averaged $3.29 per BOE compared with $3.39 per BOE for 2003.
- Production expenses per BOE are down year-over-year reflecting the increased volumes at Tommy Lakes and the emphasis that Focus places on minimizing the cost structure of the Trust.
- Average production expenses for 2005 are forecast to be in the range of $3.40 to $3.50 per BOE.

General and Administrative Expenses

(thousands)	Three Months Ended December 31, 2004	2003	Years Ended December 31, 2004	2003
Cash G&A expenses[1]	**$ 1,557**	$ 1,230	**$ 5,713**	$ 3,763
Overhead recoveries	**(465)**	(269)	**(1,667)**	(1,221)
Total cash G&A expenses	**1,092**	961	**4,046**	2,542
Non-cash G&A expense[2]	**276**	164	**1,174**	839
Trust Unit Rights Plan expense[3]	**126**	157	**306**	246
Net G&A reported	**$ 1,494**	$ 1,282	**$ 5,526**	$ 3,627
Cash-based G&A per BOE	**$ 1.21**	$ 1.06	**$ 1.13**	$ 0.81
Net reported G&A per BOE	**$ 1.66**	$ 1.83	**$ 1.54**	$ 1.16

(1) AMOUNTS PAID FOR THE TECHNICAL SERVICES AGREEMENT IN THE FIRST HALF OF 2003 WERE REPORTED SEPARATELY ON THE CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED INCOME, AND NOT INCLUDED AS PART OF GENERAL AND ADMINISTRATIVE EXPENSES. THE TECHNICAL SERVICES AGREEMENT EXPIRED JUNE 30, 2003.

(2) GROSS GENERAL AND ADMINISTRATIVE EXPENSES FOR 2004 INCLUDED $2.3 MILLION ASSOCIATED WITH THE EXECUTIVE BONUS PLAN (2003 - $1.7 MILLION). HALF OF THIS AMOUNT IS NON-CASH AND SETTLED THROUGH THE ISSUANCE OF UNITS FROM TREASURY AT A PRICE EQUAL TO THE AVERAGE OF THE LAST FIVE TRADING DAYS OF THE MONTH FOR WHICH THE BONUS RELATES.

(3) TRUST UNIT RIGHTS PLAN COMPENSATION EXPENSE IS CALCULATED USING THE FAIR VALUE METHOD ADOPTED IN 2003 AND REPRESENTS A NON-CASH CHARGE. DETAILS OF THIS COMPENSATION EXPENSE ARE CONTAINED IN NOTE 10 OF THE NOTES TO THE FINANCIAL STATEMENTS.

Cash-based general and administrative expenses were $1.21 per BOE for the fourth quarter and $1.13 per BOE for 2004. This compares with $1.06 per BOE for the fourth quarter of 2003 and $0.81 per BOE for 2003. Increased general and administrative expenses in 2004 result from increased staff levels and office expenses corresponding to the expiry of the Technical Services Agreement on June 30, 2003, and strengthening our technical group as part of the organic growth initiatives and expanded operations.

Interest and Financing Expenses

Interest and financing expenses increased $1.1 million to $2.5 million in 2004 compared to $1.4 million in 2003 commensurate with higher debt balances. Long-term debt was $74.5 million at December 31, 2004 compared to $21.3 million at December 31, 2003. Bank debt was utilized to partially fund the Tommy Lakes acquisition and to fund the acquisition of interests at Medicine Hat. Financing expenses increased $0.3 million to $0.4 million in 2004 as the Trust restructured and increased its bank credit facilities to a syndicated credit facility with four Canadian financial institutions.

Depletion and Depreciation

The depletion and depreciation rate increased to $10.42 per BOE in the fourth quarter of 2004 compared to $8.09 per BOE in the fourth quarter of 2003. The increase reflects actual capital expenditures and updated estimates of proved reserves. In addition, the acquisitions at Tommy Lakes and Medicine Hat increased the depletion rate as the Trust recorded a higher proportionate cost per BOE of proved reserves compared to the existing asset base of the Trust. The depletion rate of $10.42 per BOE in the fourth quarter of 2004 includes $0.22 per BOE related to the estimated asset retirement obligation.

Asset Retirement Obligation

In the first quarter of 2004, we adopted the CICA new section 3110, Asset Retirement Obligations. This new standard requires that companies recognize the liability associated with future site reclamation costs in the financial statements at the time when the liability is incurred. This liability is initially measured at fair value and subsequently adjusted for the accretion of the discount amount and any changes in the underlying cash flows. The asset retirement cost is capitalized to the related asset and amortized into earnings over time. The impact of the adoption of this new accounting policy is described in Notes 3 and 6 of the financial statements.

The asset retirement obligation increased $4.0 million to $11.4 million at December 31, 2004 from $7.4 million at December 31, 2003. The increase reflects additional liabilities associated with the properties acquired during the year as well as new drilling activity. Accretion expense increased by $0.2 million to $0.6 million in 2004 from $0.4 million in 2003 commensurate with the increase in the asset retirement obligation liability.

Income and Other Taxes

Income and other taxes include a future income tax recovery of $4.2 million in 2004 compared to a recovery of $0.8 million in 2003. The recovery of future income tax results from a reduction in corporate income tax rates in 2004 as well as from distributions to Unitholders which transfers taxable income from the Trust to individual Unitholders.

Capital Expenditures

Capital expenditures for field operations increased to $11.3 million in the fourth quarter of 2004 as Focus continued activity at Pouce Coupe and initiated the winter development program at Tommy Lakes. The Trust drilled eight wells at several of our key development areas during the quarter. Five wells were drilled at Tommy Lakes and one well at each of the Pouce Coupe, Loon Lake and Sylvan Lake properties.

For 2004, total capital expenditures for field operations were $25.2 million, excluding the amount recorded for asset retirement obligations. Sixty-four percent was spent at Tommy Lakes, 20 percent at other natural gas areas, 10 percent for development work at Loon Lake, and six percent in other areas. Focus continues to maximize the value of our existing asset base and acquired properties through the drill bit. Capital investment in 2004 has been focused on natural gas development opportunities and those projects which we operate and control.

Focus invested $129.7 million during 2004 to acquire high-quality natural gas properties which have long reserve life indices and significant development opportunities.

The most significant acquisition completed during the year was the purchase of additional working interests in Tommy Lakes on April 1, 2004 for $110 million. Tommy Lakes is a high-quality, long-life natural gas property which has a large accumulation of natural gas in place. It is the principal natural gas producing asset of the Trust. This property is operated by Focus, has low operating costs and a decline rate of less than 14 percent. The Tommy Lakes area contains the main development opportunities for Focus.

On September 1, 2004 Focus invested $18.6 million for the acquisition of interests at Medicine Hat, excluding the associated amounts recorded for asset retirement obligations and future income tax. With this transaction, Focus acquired a new shallow gas property in southeastern Alberta with approximately 10.8 Bcf of natural gas reserves, associated facilities and 5,760 net acres of undeveloped land. This is a long reserve life property which has significant opportunities for infill and step-out drilling. Additional interests in this property were acquired during the fourth quarter for $1.1 million.

Focus will be actively drilling in 2005 with a capital budget for field operations of $27 to $30 million. Development is expected to continue at Tommy Lakes, Pouce Coupe, Loon Lake and Sylvan Lake. Our first round of drilling at Medicine Hat is expected to occur during the first half of 2005. Capital investment in 2005 will be disciplined and directed towards the best opportunities. There will clearly be a continued emphasis on natural gas development and on those projects that we operate.

Liquidity and Capital Resources

As at December 31, 2004 Focus had a working capital deficit of $6.6 million compared with a working capital deficit of $3.3 million at December 31, 2003. The working capital deficit has increased from the $2.5 million at September 30, 2004, due to the significant winter development program which commenced in the fourth quarter of 2004. On a monthly basis, there are fluctuations in accounts receivable and accounts payable reflecting the extent of capital programs, distributions to Unitholders after month-end, and accrued revenue and royalties for the current month.

Long-term debt at December 31, 2004 was $74.5 million compared with $21.3 million at December 31, 2003 and $72.7 million at September 30, 2004. The increase in long-term debt during 2004 resulted from the acquisitions during the year which were financed with $59.3 million of long-term debt. Focus had a $100 million revolving syndicated credit facility among four financial institutions and a $10 million operating facility at December 31, 2004. The credit facility revolves until May 26, 2005.

Long-term debt less working capital increased $56.5 million during 2004. This change primarily resulted from the following factors.

- The acquisition on April 1, 2004 for $110 million was financed with the issuance of Trust Units for net proceeds of $70.4 million and $39.6 million from bank credit facilities.
- The acquisitions at Medicine Hat of $19.7 million were financed with bank credit facilities.
- Proceeds of $0.8 million from the issuance of equity pursuant to the exercise of Unit Appreciation Rights
- Funds flow from operations were $89.6 million, of which $61.4 million in distributions were declared to Unitholders, $25.2 million was invested in capital expenditures for field operations, $1.0 million was paid to the reclamation fund and $2.0 million went to debt repayment.

Focus plans to finance its program for development drilling and enhancement of production primarily through investing approximately 25 to 30 percent of funds flow. Capital expenditures, including acquisitions, above this level will be financed through a combination of cash flow, debt and equity by issuing Units from treasury.

Capitalization Table

(thousands except per-Unit amounts)		**December 31, 2004**		December 31,2003
Long-term debt	**$**	**74,500**	$	21,337
Plus: Working capital deficiency		**6,658**		3,304
Total debt	**$**	**81,158**	$	24,641
Units outstanding and issuable for Exchangeable Shares		**37,223**		31,822
Market price	**$**	**19.97**	$	15.00
Market capitalization	**$**	**743,343**	$	477,330
Total capitalization	**$**	**824,501**	$	501,971
Total debt as a percentage of total capitalization		**9.8%**		4.9%
Funds flow	**$**	**89,567**	$	65,808
Total debt to funds flow		**0.9**		0.4

Cash Distributions

We announce our distribution policy on a quarterly basis. The actual amount of the cash distribution is determined by the Board of Directors and is dependent upon the commodity price environment, production levels, and the amount of capital expenditures to be funded from cash flow. Our distribution policy incorporates the withholding of approximately 25 percent of cash flow for the financing of capital expenditures to provide more sustainable distributions. Cash distributions are essentially taxed to the Unitholders as ordinary income.

Focus declared distributions of $1.80 per Unit in respect of 2004 production. Distributions were increased twice during 2004. Distributions per Unit in 2004 were $0.14 for the first quarter, $0.15 for the second and third quarters and $0.16 for the fourth quarter. On January 14th, 2005 Focus announced a continuation of the distribution policy of monthly distributions of $0.16 per Unit for the first quarter of 2005.

The Exchangeable Shares of FET Resources Ltd. are convertible into Trust Units of Focus based on the exchange ratio, which is adjusted monthly to reflect the cash distribution paid on the Trust Units. Cash distributions are not paid on the Exchangeable Shares and the cash flow related to the Exchangeable Shares is retained by the Trust for reduction of debt or for additional capital expenditures. The initial exchange ratio was one Trust Unit for one Exchangeable Share. The exchange ratio at December 31, 2004 was 1.27833. Effective March 15, 2005 the exchange ratio is 1.30129 Trust Units for one Exchangeable Share.

Payout Ratio		**Year Ended December 31, 2004**		Year Ended December 31,2003
Funds flow from operations (thousands)	**$**	**89,567**	$	65,808
Funds flow from operations per Total Unit (weighted average Total Trust Units, including Exchangeable Shares converted at the average exchange ratio)	**$**	**2.49**	$	2.16
Distributions per Unit declared	**$**	**1.80**	$	1.665
Payout ratio - per-Unit basis		**72%**		77%
Cash distributions declared to Unitholders; Exchangeable Shares do not receive cash distributions (thousands)	**$**	**61,439**	$	42,342
Payout ratio - dollar basis		**69%**		64%

Contractual Obligations and Commitments

The Trust has contractual obligations in the normal course of operations including purchase of assets and services, operating agreements, transportation commitments and sales commitments. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner.

The following table is a summary of all contractual obligations and commitments for the next five years.

Contractual Obligations[1]

($thousands)	Total	2005	2006-2007	2008-2009	2010 and thereafter
Office premises	2,193	74	707	1,028	384
Operating leases	396	132	264	–	–
Mineral and surface leases[2]	4,318	720	1,439	1,439	720
Transportation and processing	23,971	9,420	9,433	2,515	2,603
Asset retirement obligations[3]	10,922	215	427	310	9,970
Total contractual obligations	41,800	10,561	12,270	5,292	13,677

(1) THE TABLE DOES NOT INCLUDE THE TRUST'S OBLIGATIONS FOR FINANCIAL INSTRUMENTS AND PHYSICAL SALES CONTRACTS WHICH ARE FULLY DISCLOSED IN NOTES 12 AND 13 OF THE FINANCIAL STATEMENTS.

(2) THE TRUST MAKES PAYMENTS FOR MINERAL AND SURFACE LEASES. THE TABLE INCLUDES PAYMENTS FOR EACH OF THE YEARS 2005 TO 2010 UNDER THESE LEASES ASSUMING CONTINUATION OF THE LEASES. THE CONTINUATION OF LEASES IS BASED ON DECISIONS BY THE TRUST RELATING TO EACH OF THE UNDERLYING PROPERTIES. PAYMENTS FOR THE PERIOD AFTER 2010 HAVE NOT BEEN INCLUDED IN THE TABLE, BUT WOULD CONTINUE AT THE SAME YEARLY RATE IF THERE WAS NO CHANGE TO THE UNDERLYING PROPERTIES.

(3) BASED ON THE ESTIMATED TIMING OF EXPENDITURES TO BE MADE IN FUTURE PERIODS

Off Balance Sheet Arrangements

The Trust has certain lease agreements that are entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as at December 31, 2004.

Focus has not entered into any guarantee or off balance sheet arrangements that would adversely impact the Trust's financial position or results of operations.

Taxation of Cash Distributions

Focus Energy Trust, for purposes of the Canadian Income Tax Act, is treated as a mutual fund trust and each year the Trust files an income tax return with the taxable income allocated to the Unitholders. Distributions paid to the Unitholders may be both a return on capital (income) and a return of capital. The allocation between these two streams is dependent upon the income tax deductions that the Trust is able to claim against the income it earns. The return of capital portion reduces the adjusted cost base of the Trust Units held.

The Trust has net income for each year that is required to be calculated on an accrual basis of accounting, not a cash basis. Net income includes all interest income from FET and other income that accrues to the Trust to the end of the year. Under the Trust Indenture, net income of the Trust for each year will be paid or payable by way of cash distributions to the Unitholders.

Taxable income of the Trust includes a deduction for the allocation of taxable income to Unitholders, which is paid or becomes payable in the year and a deduction relating to income tax pools residing at the Trust level. The Trust Indenture provides that an amount at least equal to the taxable income of the Trust must be paid or payable each year to Unitholders in order to reduce the Trust's taxable income to zero. Such taxable income is allocated to Unitholders. Any taxable income relating to a payable amount is allocated to Unitholders of record at the end of the year, and each Unitholder receives a pro rata share of that payable amount.

For 2004, cash distributions will be 97.5 percent return on capital (taxable) and 2.5 percent return of capital (tax deferred). For a more detailed breakdown as well as tax information for U.S. investors, please visit our website at www.focusenergytrust.com.

2004 Canadian Tax Information

The following information is intended to assist Canadian holders of Trust Units of Focus Energy Trust (FET.UN – TSX) in the preparation of their 2004 T1 Income Tax Return. This summary is directed to a Unitholder who, for purposes of the Income Tax Act (Canada), is a resident of Canada and holds the Units as capital property. Other Unitholders are advised to consult with their tax advisor concerning their circumstances.

- **Trust Units held within an RRSP, RRIF or DPSP** - NO AMOUNTS are to be reported on the 2004 income tax return where Trust Units are held within a Registered Retirement Savings Plan (RRSP), Registered Retirement Income Fund (RRIF), Deferred Profit Savings Plan (DPSP), or any other such registered plans.
- **Trust Units held outside of an RRSP, RRIF or DPSP** - If the Trust Units are held through a broker or other intermediary then the Unitholder will receive a T3 Supplementary slip directly from the Unitholder's broker or intermediary, not from the transfer agent (Valiant Trust Company) nor from Focus, no later than March 31, 2005.
- If the Unitholder is a registered holder then the Unitholder will receive a T3 Supplementary slip directly from Valiant Trust Company.
- The amount reported in Box (26) on the T3 Supplementary slip, "Other Income", should be reported on the 2004 T1 Income Tax Return.

Taxable Income Allocated to Unitholders for 2004 and Taxation Treatment

- For those Unitholders who held their Focus Energy Trust Units outside of a registered plan, the return on capital or income portion is reported in Box (26) of the T3 Supplementary slip, "Other Income", and should be reported on the 2004 T1 Income Tax Return.
- In most circumstances, the return of capital portion will reduce the Unitholder's adjusted cost base of their Focus Energy Trust Units. This is discussed in more detail below.
- The following table outlines the breakdown of cash distributions per Unit paid by Focus Energy Trust with respect to record dates for the period January 31 to December 31, 2004.

Record Date	Payment Date	Distribution Paid	Taxable Income (Box 26 Other Income)	Return of Capital Amount
January 31, 2004	February 16, 2004	$ 0.14	$ 0.1365	$ 0.0035
February 29, 2004	March 15, 2004	$ 0.14	$ 0.1365	$ 0.0035
March 31, 2004	April 15, 2004	$ 0.14	$ 0.1365	$ 0.0035
April 30, 2004	May 17, 2004	$ 0.15	$ 0.1462	$ 0.0038
May 31, 2004	June 15, 2004	$ 0.15	$ 0.1462	$ 0.0038
June 30, 2004	July 15, 2004	$ 0.15	$ 0.1462	$ 0.0038
July 31, 2004	August 16, 2004	$ 0.15	$ 0.1462	$ 0.0038
August 31, 2004	September 15, 2004	$ 0.15	$ 0.1462	$ 0.0038
September 30, 2004	October 15, 2004	$ 0.15	$ 0.1462	$ 0.0038
October 31, 2004	November 15, 2004	$ 0.16	$ 0.1560	$ 0.0040
November 30, 2004	December 15, 2004	$ 0.16	$ 0.1560	$ 0.0040
December 31, 2004	January 17, 2005	$ 0.16	$ 0.1560	$ 0.0040
Total		$ 1.800	$ 1.7547	$ 0.0453

Adjusted Cost Base

In most circumstances, the return of capital portion will reduce the Unitholder's adjusted cost base of their Focus Energy Trust Units. The adjusted cost base of the Units is required in the calculation of a capital gain or capital loss (if capital property to the Unitholder) upon the disposition of the Units.

Should a Unitholder's adjusted cost base ever be reduced below zero, that negative amount is deemed to be a capital gain and the adjusted cost base is deemed to be nil. The capital gain is reported on Schedule 3 of the T1 Income Tax Return.

2004 United States Tax Information

The following information is being provided to assist U.S. individual Unitholders of Focus Energy Trust ("Focus") in reporting distributions received from Focus during 2004 on their Internal Revenue Service ("IRS") Form 1040 – U.S. Individual Income Tax Return ("Form 1040") for 2004.

Focus has not obtained a legal or tax opinion, nor has it requested a ruling from the IRS on these matters.

- **Trust Units Held Outside of a Qualified Retirement Plan** – For distributions relating to 2004, 100 percent of the distributions should be considered taxable as dividends to the Unitholder for U.S. federal income tax purposes. After consulting with its tax advisors, Focus believes that its distributions should be considered "Qualified Dividends" under the Jobs and Growth Tax Relief Reconciliation Act of 2003 and should be eligible for the reduced U.S. dividend tax rate. However, the individual taxpayer's situation must be considered before making this determination. "Qualified Dividends" should be reported on Line 9(b) of the IRS Form 1040, unless the facts of the U.S. individual Unitholder determine otherwise. Page 20 of the IRS 2004 Form 1040 Instruction Booklet provides examples of individual situations where the distributions would not be "Qualified Dividends". Where the distributions are not considered "Qualified Dividends" due to an individual's situation, the amount should be reported on Schedule B, Part ii – Ordinary Dividends and Line 9 (a) of your IRS Form 1040.

  For the non-taxable portion of distributions, if any, ("Non-Taxable Return of Capital"), a taxpayer must reduce the cost (or other basis) by the amount of non-taxable distributions in calculating the gain or loss on sale of Focus Units. If the amount of "Non-Taxable Return of Capital" exceeds your cost (or other basis), report the excess as a capital gain.

  U.S. Unitholders are encouraged to utilize the Qualified Dividends and Capital Gain Tax Worksheet provided by the IRS to determine the amount of tax applicable.

  Canadian withholding taxes that have been withheld from the taxable portion of your distributions (as computed under Canadian tax principles) should be reported on Form 1116 "Foreign Tax Credit (Individual, Estate or Trust)". Amounts overwithheld should be claimed as a refund from the Canada Revenue Agency and should not be claimed as a credit against your U.S. federal income tax liability. Information regarding the amount of Canadian tax withheld relating to 2004 distributions should be available through your investment advisor or other intermediary and is not available from Focus.

- **Trust Units Held Within a Qualified Retirement Plan** – There should be no amount that is required to be reported as income on an IRS Form 1040 where the Focus Trust Units are held in a Qualified Retirement Plan.

The above information is not meant to be an exhaustive discussion of all possible U.S. income tax considerations, but a general guideline and is not intended to be legal or tax advice to any particular holder or potential holder of Focus Energy Trust Units. Holders or potential holders of Trust Units should consult their own tax advisors as to their particular tax consequences of holding Trust Units.

Management and Financial Reporting Systems

The Trust's management and internal control systems are designed to provide assurance that accurate and timely internal and external information is communicated to users of that information. These systems are continually being reviewed for opportunities for enhancement.

Update on Financial Reporting and Regulatory Matters

The following new accounting policies impacted the Trust in 2004:

- Asset Retirement Obligations

  In 2004, the Trust adopted the CICA new section 3110, Asset Retirement Obligations. This new standard requires that companies recognize the liability associated with future site reclamation costs in the financial statements at the time when the liability is incurred. This liability is initially measured at fair value and subsequently adjusted for the accretion of the discount amount and any changes in underlying cash flows. The asset retirement cost is capitalized to the related asset and amortized into earnings over time. The impact of this new accounting policy is described in Notes 3 and 6 of the financial statements.

- Oil and Gas Accounting – Full Cost

  In 2004, the Trust adopted the recommendations contained in the Accounting Guideline 16, "Oil and Gas Accounting – Full Cost".

  The guideline impacts the cost impairment test or ceiling test. The cost impairment test is a two stage test which is to be performed annually. The first stage of the test determines if the cost pool has been impaired. An impairment occurs when the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows from proved reserves plus unproved costs using management's best estimate of future prices. The second stage of the test involves measurement of the impairment. The impairment is measured as the amount by which the carrying amount of capitalized assets exceeds the future discounted cash flows from proved plus probable reserves. The discount rate used is the company's risk free rate. The guideline requires disclosure of future prices used in the measurement of impairment.

  Adoption of this new guideline resulted in no changes to net income, petroleum and natural gas assets or any other reported amounts in the consolidated financial statements.

- Hedging Relationships

  In 2004, the Trust adopted Accounting Guideline 13, "Hedging Relationships", which deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting.

  The Trust has determined that all financial instruments met the criteria of effective hedges in 2004.

- Transportation System Charges

  Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles", which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation system charges against revenue rather than showing the charges as a separate expense on the income statement. Effective January 1, 2004, the Trust has recorded revenue gross of transportation system charges and a transportation system charge on the income statement. Prior periods have been reclassified for comparative purposes. This adjustment has no impact on net income or cash flow for the Trust.

- EIC-151, Exchangeable Securities Issued by Subsidiaries of Income Trusts

  In 2005, the Trust will be required to adopt the recommendations contained in EIC-151, Exchangeable Securities Issued by Subsidiaries of Income Trusts. The abstract will require the Trust to reclassify the amounts recorded as exchangeable shares from Unitholders' capital to non-controlling interests. The revision will be effective for periods on or after June 30, 2005. This accounting policy change is required to be applied retroactively and as a result, the financial statements will be restated.

Other future possible accounting policy changes include:

- Variable Interest Entities

  In June 2003 the CICA issued Accounting Guideline 15, "Consolidation of Variable Interest Entities", which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004.

  The Trust has assessed that this new guideline is not applicable based on the current structure of the Trust.

- Financial Instruments - Recognition and Measurement, Hedges, and Comprehensive Income

  The CICA has issued three exposure drafts on financial instruments which will apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. It will require the following:
  - all trading financial instruments will be recognized on the balance sheet and will be fair valued through the income statement;
  - all remaining financial assets will be recorded at cost and amortized through the financial statements;
  - a new statement for comprehensive income that will include certain gains and losses on translation of assets and liabilities; and
  - an update to Accounting Guideline 13 to incorporate the fair value changes not recorded in the income statement to be recorded through the comprehensive income statement.

The Trust has not assessed the future impact on the financial statements at this time.

- Changes in Accounting Policies and Estimates and Errors

  The CICA has proposed a new Handbook section 1506 "Changes in accounting policies and estimates, and errors" to provide guidance around when and how an entity is permitted to change an accounting policy as well as establish appropriate disclosures to explain the effects of changes in accounting policy, estimates and corrections of errors.

- Subsequent Events

  The CICA has proposed to extend the period during which subsequent events are required to be considered. This period is between the balance sheet date and when the financial statements are authorized for issue. In addition, disclosure is required as to the date the financial statements were authorized for issue and who provided that authorization.

SUMMARY OF QUARTERLY RESULTS

The following table provides a summary of results for each of the last eight quarters. Significant factors and trends which have impacted these results include:

- Revenue and royalties are directly related to fluctuations in the underlying commodity prices and the extent to which price protection has been achieved through financial hedges and forward physical sales contracts.
- Focus operates the majority of its capital programs during the winter season. As such, the majority of the capital expenditures and associated overhead recoveries occur in the winter months. The winter drilling programs have resulted in increased production, which is strongest in the second quarter due to the initial flush production from the new wells.
- Our main natural gas properties are in winter-only access areas of British Columbia, and production expenses per BOE are the highest in the first and fourth quarters when these properties are accessible for maintenance and the restocking of supplies. The weighting of production towards natural gas has increased, and natural gas production generally has lower production expenses on a per-BOE basis.
- Focus has completed acquisitions at Loon Lake in June 2003, Tommy Lakes in April 2004 and Medicine Hat in September 2004. The acquisitions were funded through the use of existing bank credit facilities and the issuance of equity in June 2003 and March 2004.
- Focus was created in August 2002 and has continually been developing its organization with the addition of professional and technical staff.

The table below highlights Focus' quarterly performance for the years ended December 31, 2004 and 2003. Refer to page 44 for more detailed quarterly information.

Quarter Ended	**2004**				2003			
(thousands of dollars, except per-Unit amounts)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Oil and gas revenues, before royalties[1]	**39,233**	**37,979**	**42,284**	**30,677**	28,088	28,806	31,979	30,494
Net income	**15,451**	**13,546**	**17,286**	**13,346**	10,456	10,608	12,449	7,960
Per Unit – basic	**$ 0.42**	**$ 0.37**	**$ 0.47**	**$ 0.41**	$ 0.33	$ 0.34	$ 0.42	$ 0.27
– diluted	**$ 0.41**	**$ 0.36**	**$ 0.47**	**$ 0.41**	$ 0.33	$ 0.33	$ 0.43	$ 0.27

(1) RESTATED AT DECEMBER 31, 2004 TO BREAK OUT THE TRANSPORTATION SYSTEM CHARGES SEPARATELY (INCREASES REVENUE AND RECORDS THIS EXPENSE SEPARATELY)

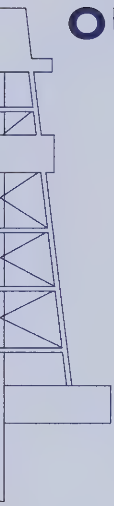
Assessment of Business Risks

Following are the primary risks associated with the business of the Trust. These risks are similar to those affecting others in the conventional oil and gas income trust sector. The Trust's financial position, results of operations and distributions to Unitholders are directly impacted by these factors:

1. operational risk associated with the production of oil and natural gas;
2. reserve risk in respect to the quantity and quality of recoverable reserves;
3. market risk relating to the availability of transportation systems to move the product to market;
4. commodity risk as crude oil and natural gas prices fluctuate due to market forces;
5. financial risk such as the Canadian/U.S. dollar exchange rate, interest rates and debt service obligations;
6. environmental and safety risk associated with well operations and production facilities;
7. change in laws, regulation and administrative practice of governmental authorities relating to the oil and natural gas industry and the trust sector, particularly with respect to operations, environmental controls, royalties and income taxes, including changes in foreign ownership rules and changes to the taxation of trusts.

Focus seeks to mitigate these risks by:

1. acquiring mature properties to reduce technical uncertainty;
2. acquiring long-life reserves to ensure more stable production and to reduce the economic risks associated with commodity price cycles;
3. maintaining a low-cost structure to maximize product netbacks and reduce impact of commodity price cycles;
4. diversifying properties to mitigate individual property and well risk;
5. maintaining a product mix to balance exposure to commodity prices;
6. conducting rigorous reviews of all property acquisitions;
7. monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
8. maintaining a hedging program to hedge commodity prices and foreign exchange currency rates with creditworthy counterparties;
9. ensuring strong third-party operators for non-operated properties;
10. adhering to the Trust's safety program and keeping abreast of current operating best practices;
11. keeping informed of proposed change in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
12. carrying insurance to cover losses and business interruption;
13. establishing and building cash resources to fund future site reclamation costs.



OUTLOOK

The Trust's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by demand and supply factors, including weather and general economic conditions as well as conditions in other oil and natural gas producing regions.

The following chart summarizes Focus' 2005 outlook. No acquisitions are assumed for the purposes of these forecasts.

In 2005, Focus will continue its active drilling and development programs on its major properties. It is anticipated that these development activities will maintain production by offsetting production declines.

We do not attempt to forecast commodity prices, and as a result, we do not forecast funds flow from operations or future cash distributions to Unitholders.

Summary of 2005 Expectations

Average annual production	10,000 - 10,500 BOE/D
Weighting to natural gas	75%
Production expenses per BOE	$ 3.40 – $ 3.50
Cash G&A expenses per BOE	$ 1.25 – $ 1.35
Capital expenditures - field	$ 27 million - $ 30 million
Average annual payout ratio	70% – 80%
Approximate taxable portion of distributions	100%
Funds from operations / net debt	Under 1x

The table below shows the potential impact on the Trust's funds flow (before price protection) resulting from changes to the business environment or operations.

	Change	Change to Funds Flow $000s	$ / Unit
Business Environment			
Price per barrel of crude oil (US$ WTI)	$ 1.00	771	0.021
Price per mcf of natural gas (CDN$ AECO)	$ 0.25	3,017	0.081
US / CDN exchange rate	$ 0.01	1,095	0.029
Interest rate on debt	1%	745	0.020
Operations			
Oil production - bbls/d	100	1,381	0.037
Gas production - mcf/d	1,000	1,700	0.046
Operating expenses ($ per BOE)	$ 0.25	935	0.065
Cash G&A expenses ($ per BOE)	$ 0.25	935	0.025

Focus is committed to increasing the long-term value of the Trust to Unitholders. The following goals are the foundation of our commitment to value creation:

- Maximize the value of existing assets;
- Attract and retain the best value creation team in the business;
- Pursue quality acquisitions that are strategic and accretive;
- Protect margins and improve profitability;
- Surface value through operational expertise and control;
- Maintain financial flexibility and strength.

MANAGEMENT'S RESPONSIBILITY

Management is responsible for the preparation of the accompanying consolidated financial statements and for the consistency therewith of all other financial and operating data. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes thereto. In management's opinion, the consolidated financial statements are in accordance with Canadian generally accepted accounting principles and have been prepared within acceptable limits of materiality.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. Where estimates are used in the preparation of these financial statements, management has ensured that careful judgment has been made and that these estimates are reasonable, based on all information known at the time the estimates are made.

Independent auditors appointed by the Trustee have examined and expressed their opinion on the consolidated financial statements of the Trust. The Audit Committee, consisting of independent directors of FET Resources Ltd., has reviewed these consolidated financial statements with management and the auditors, and has recommended them to the Board of Directors for approval. The Board has approved the consolidated financial statements of the Trust.

Derek W. Evans
President and Chief Executive Officer
February 28, 2005

William D. Ostlund
Vice President, Finance and Chief Financial Officer

AUDITOR'S REPORT

To the Unitholders of Focus Energy Trust:

We have audited the consolidated balance sheet of Focus Energy Trust as at December 31, 2004 and 2003 and the consolidated statements of income and accumulated income and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance that the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Alberta, Canada
February 28, 2005

CONSOLIDATED BALANCE SHEETS

	Years Ended, December 31, 2004	2003
ASSETS		
Current assets		
Cash and cash equivalents	**$ 43,732**	$ –
Accounts receivable	**20,220,594**	20,043,512
Prepaid expenses and deposits	**1,697,846**	1,092,559
	21,962,172	21,136,071
Petroleum and natural gas properties and equipment [note 4]	**302,454,785**	174,974,307
Goodwill [note 5]	**5,100,000**	–
Reclamation fund [note 7]	**1,922,519**	1,030,000
	$ 331,439,476	$ 197,140,378
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**$ 22,864,458**	$ 20,515,765
Cash distributions payable	**5,755,784**	3,924,783
	28,620,242	24,440,548
Long-term debt [note 8]	**74,500,000**	21,336,532
Asset retirement obligation [note 6]	**11,461,469**	7,442,069
Future income taxes [note 15]	**43,727,120**	41,686,533
	158,308,831	94,905,682
UNITHOLDERS' EQUITY		
Unitholders' capital [note 9]	**139,335,147**	63,267,421
Exchangeable Shares [note 9]	**1,546,884**	5,160,995
Contributed surplus	**498,516**	245,524
Accumulated income	**145,289,496**	85,661,322
Accumulated cash distributions	**(113,539,398)**	(52,100,566)
	173,130,645	102,234,696
Commitments and contingencies [note 17]		
	$ 331,439,476	$ 197,140,378

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Approval on behalf of the Board:

STUART G. CLARK
DIRECTOR

GERALD A. ROMANZIN
DIRECTOR

CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED INCOME

	Years Ended, December 31, 2004	2003 (Restated – Note 3)
Revenue		
Production revenue	**$ 150,172,892**	$ 119,366,943
Royalties	**(34,551,035)**	(30,789,864)
Alberta Royalty Tax Credit	**475,080**	287,512
Facility income	**2,597,273**	2,611,767
Interest income	**229,301**	64,128
	118,923,511	91,540,486
Expenses		
Transportation system charges [note 3]	**9,584,180**	7,534,600
Production	**11,790,150**	10,590,468
Technical Services Agreement	**–**	2,100,000
General and administrative	**5,525,776**	3,627,275
Interest and financing	**2,515,545**	1,386,761
Depletion and depreciation [note 4]	**32,007,125**	25,065,441
Accretion of asset retirement obligation [note 6]	**664,001**	420,078
	62,086,777	50,724,623
Income before income and other taxes	**56,836,734**	40,815,863
Income and other taxes [note 15]		
Future income tax expense (reduction)	**(4,212,000)**	(854,505)
Current and large corporations tax	**1,420,560**	224,366
	(2,791,440)	(630,139)
Net income for the period	**59,628,174**	41,446,002
Accumulated income, beginning of period		
As previously reported	**85,820,667**	44,348,355
Retroactive adjustment for changes in accounting policies	**(159,345)**	(133,035)
As restated	**85,661,322**	44,215,320
Accumulated income, end of period	**$ 145,289,496**	$ 85,661,322
Net income per Unit [note 14]		
Basic	**$ 1.66**	$ 1.36
Diluted	**$ 1.65**	$ 1.36

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended, December 31, 2004	2003 (Restated – Note 3)
Operating activities		
Net income for the period	**$ 59,628,174**	$ 41,446,002
Add non-cash items:		
Non-cash general and administrative expenses [note 10]	**1,479,707**	1,084,483
Unrealized (gain) loss on commodity contract	**–**	(1,353,067)
Depletion and depreciation	**32,007,125**	25,065,441
Accretion on asset retirement obligation	**664,001**	420,078
Future income tax expense	**(4,212,000)**	(854,505)
Funds flow from operations	**89,567,007**	65,808,432
Net change in non-cash working capital items	**1,940,194**	6,145,326
	91,507,201	71,953,758
Financing activities		
Proceeds from issue of Trust Units (net of costs)	**70,419,265**	23,891,651
Proceeds from exercise of Unit Appreciation Rights	**854,040**	158,048
Increase (decrease) in long-term debt	**53,163,468**	(30,464,468)
Cash distributions	**(59,607,831)**	(40,925,594)
	64,828,942	(47,340,363)
Investing activities		
Capital asset additions	**(25,156,145)**	(16,809,155)
Acquisition expenditures [note 5]	**(130,181,848)**	(22,175,416)
Proceeds on disposal of capital assets	**–**	1,958,669
Reclamation fund contributions and actual expenditures	**(1,016,677)**	(1,291,346)
Net change in non-cash working capital items	**62,259**	(1,001,181)
	(156,292,411)	(39,318,429)
Increase in cash and cash equivalents during the period	**43,732**	(14,705,034)
Cash and cash equivalents, beginning of period	**–**	14,705,034
Cash and cash equivalents, end of period	**$ 43,732**	$ –

SEE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2004 AND 2003 (AUDITED)

1. STRUCTURE OF THE TRUST

Focus Energy Trust (the "Trust") was established on August 23, 2002 under a Plan of Arrangement involving the Trust, Storm Energy Inc., FET Resources Ltd., and Storm Energy Ltd. The Trust is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a trust indenture (the "Trust Indenture"). Valiant Trust Company has been appointed Trustee under the Trust Indenture. The beneficiaries of the Trust are the holders of the Trust Units (the "Unitholders").

FET Resources Ltd. (the "Company") is a subsidiary of the Trust. Under the Plan of Arrangement, the Company became the successor company to Storm Energy Inc. through amalgamation on August 23, 2002. The Company is actively engaged in the business of oil and natural gas exploitation, development, acquisition and production.

2. SUMMARY OF ACCOUNTING POLICIES

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of these consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Correspondingly, actual results could differ from estimated amounts. These consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

In particular, the amounts recorded for depletion and depreciation of the petroleum and natural gas properties and equipment and for asset retirement obligations are based on estimates of reserves and future costs. The cost impairment test is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of future periods could be material.

a) Principles of Consolidation

The consolidated financial statements of the Trust include the accounts of Focus Energy Trust, its subsidiaries FET Resources Ltd. and FET Gas Production Ltd. and Focus B.C. Trust, and its share of two partnerships. All inter-entity transactions and balances have been eliminated.

b) Petroleum and Natural Gas Properties and Equipment

The Trust follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of acquiring petroleum and natural gas properties and related development costs, whether productive or unproductive, are capitalized and accumulated in one Canadian cost centre, including asset retirement costs. Such costs include acquisition, drilling, geological, geophysical, and equipment costs and overhead expenses related to the properties and development activities. Costs of acquiring and evaluating unproved properties are excluded from depletion calculations until it is determined in the period that proved reserves are attributable to the properties or impairment has occurred. Maintenance and repairs are charged against income, and renewals and enhancements which extend the economic life of the properties and equipment are capitalized. Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion by 20 percent or more.

Depletion of petroleum and natural gas properties and depreciation of equipment are provided for using the unit-of-production method based on estimated proved petroleum and natural gas reserves, before royalties, as determined by independent engineers calculated in accordance with National Instrument 51-101. Production and reserves of natural gas are converted to equivalent barrels of crude oil based on the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil. The depletion and depreciation cost base includes total capitalized costs, less prior depletion and depreciation charges, less costs of unproved properties, less the estimated future net realizable value of production equipment and facilities, plus provision for future development costs and future asset retirement costs of proved undeveloped reserves.

c) Cost Impairment Test

The Trust places a limit on the aggregate carrying value of petroleum and natural gas properties and equipment, which may be amortized against revenues of future periods (the "cost impairment test"). The cost impairment test requires an evaluation of petroleum and natural gas assets in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

Cost impairment is recognized if the carrying amount of the petroleum and natural gas properties exceeds the sum of the undiscounted cash flows expected to result from the Trust's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Trust's contract prices and quality differentials.

Upon recognition of impairment, the Trust would then measure the amount of impairment by comparing the carrying amounts of the petroleum and natural gas properties to an amount equal to the estimated net present value of future cash flows from proved plus risked probable reserves. The Trust's risk free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying amount above the net present value of the Trust's future cash flows would be recognized as a permanent impairment.

The cost of unproved properties is excluded from the cost impairment test calculation and subject to a separate impairment test.

d) Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired business. Net identifiable liabilities of the acquired business include an estimate of future income taxes. The goodwill balance is assessed for impairment annually at year end or more frequently if events change and circumstances indicate that the asset might be impaired. The test for impairment is the comparison of the carrying amount to the fair value of the reporting entity. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities at their fair values. The excess of this allocation is the fair value of goodwill. Any excess of the book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

Goodwill is stated at cost less impairment and is not amortized.

An impairment test of goodwill was completed at December 31, 2004 resulting in no impairment amount.

e) Financial Instruments

The Trust uses financial instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The Trust's policy is not to use financial instruments for speculative or trading purposes. Gains and losses on contracts which constitute effective hedges are recognized in production income at the time of sale of the related production. Financial instruments which do not qualify as hedges are recorded on a mark-to-market basis at the balance sheet date with the resulting gains or losses being taken into income in the period.

f) Income Taxes

Income taxes are calculated using the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the consolidated financial statements of the Trust and their respective tax base, using substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the Unitholders. As the Trust allocates all of its taxable income to the Unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income tax expense has been made in the Trust.

In the Trust structure, payments are made between the Company and the Trust which result in the transferring of taxable income from the Company to individual Unitholders. These payments may reduce future income tax liabilities previously recorded by the Company which would be recognized as a recovery of income tax in the period incurred.

g) Unit-Based Compensation Plan

The Trust has a Unit-based compensation plan (the "Plan") for employees, directors and consultants of the Trust and its subsidiaries which are described in Note 10. Compensation expense associated with rights granted under the Plan is deferred and recognized in earnings over the vesting period of the Plan with a corresponding increase or decrease in contributed surplus. Compensation expense is based on the fair value of the Unit-based compensation at the date of grant using a modified Black Scholes option pricing model. The fair value method has been adopted prospectively with 2003 rights granted. The pro forma impact for rights granted for the period from August 23, 2002 to December 31, 2002 using the fair value method is disclosed in Note 10.

Consideration paid upon the exercise of the rights together with the amount previously recognized in contributed surplus is recorded as an increase in Unitholders' capital.

The Trust has not incorporated an estimated forfeiture rate for rights that will not vest, rather, the Trust accounts for actual forfeitures as they occur.

h) Per-Unit Amounts

Net income per Unit is calculated using the weighted average number of Units outstanding during the year, including the weighted average number of Exchangeable Shares outstanding converted at the exchange ratio at the end of each month. Diluted net income per Unit is calculated using the treasury stock method to determine the dilutive effect of Unit-based compensation. The treasury stock method assumes that the proceeds received from the exercise of "in the money" Trust Unit rights are used to repurchase Units at the average market rate during the period. The weighted average number of Units outstanding is then adjusted by the net change.

i) Revenue Recognition

Revenue associated with sales of crude oil, natural gas, and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point for natural gas and at the wellhead for crude oil.

j) Joint Operations

Certain of the Trust's exploration and production activities are conducted jointly with others. The accounts of the Trust reflect its proportionate interest in such activities.

k) Cash and Cash Equivalents

The Trust considers all highly liquid investments with a maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist primarily of funds on deposit for various terms. Cash and cash equivalents are stated at cost which approximates fair value.

l) Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses are translated at the monthly average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

m) Comparative Figures

Certain of the comparative figures have been reclassified to conform to the current year's presentation.

3. CHANGES IN ACCOUNTING POLICIES

a) Petroleum and Natural Gas Properties and Equipment

Petroleum and natural gas assets are evaluated in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre. Effective January 1, 2004, the Trust adopted the new accounting standard relating to full cost accounting. There were no changes to net income, petroleum and natural gas assets or any other reported amounts in the consolidated financial statements as a result of adopting this guideline.

The new guideline impacts the cost impairment test or ceiling test. The cost impairment test is a two- stage test. The first stage of the test determines if the cost pool has been impaired. Impairment occurs when the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows from proved reserves plus unproved costs using management's best estimate of future prices. The second stage of the test involves measurement of the impairment. The impairment is measured as the amount by which the carrying amount of capitalized assets exceeds the future discounted cash flows from proved plus probable reserves. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

Prior to January 1, 2004 the ceiling test amount was the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost or market of unproved properties and the cost of major development projects less estimated future costs for administration, financing, site restoration and income taxes. The cash flows were estimated using period-end prices and costs.

b) Asset Retirement Obligation

The Trust has adopted the asset retirement obligation method of recording the future cost associated with removal, site restoration and asset retirement costs. The fair value of the liability for the Trust's asset retirement obligation is recorded in the period in which it is incurred, discounted to its present value using the Trust's credit adjusted risk-free interest rate and the corresponding amount recognized by increasing the carrying amount of property, plant and equipment. The asset recorded is depleted on a unit-of-production basis over the life of the reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

Previously, the Trust recognized a provision for estimated future removal and site restoration costs calculated on the unit-of-production method over the remaining proved reserves.

The effect of this change in accounting policy has been recorded retroactively with restatement of prior periods. The effect of the adoption is presented below as increases (decreases).

Balance Sheets		December 31, 2003
Petroleum and natural gas properties and equipment increased for historic asset retirement costs	$	4,069,393
Record new asset retirement obligation	$	7,442,069
Reverse historic provision for future site restoration		(3,083,021)
Adjust future income taxes		(130,310)
Adjust accumulated income		(159,345)
Increase in liabilities and Unitholders' equity	$	4,069,393

Statements of Income		Year ended December 31, 2004		Year ended December 31, 2003
Accretion expense	$	(664,001)	$	(420,078)
Depletion and depreciation on asset retirement costs		(552,952)		(644,727)
Less: Amortization of estimated future removal and site restoration liability under previous policy		2,397,535		1,000,633
Net income impact of new policy, before tax	$	1,180,582	$	(64,172)
Basic and diluted net income per share before tax	$	0.04		–

c) Financial Derivatives

Effective January 1, 2004 the Trust has implemented the new accounting guideline relating to hedging relationships. The new policy addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes the conditions for applying or discontinuing hedge accounting. Under the new guideline hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual hedge accounting.

The hedges in effect at December 31, 2004 and December 31, 2003 met the criteria of effective hedges.

d) Transportation System Charges

Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles", which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation system charges against revenue rather than showing the charges as a separate expense on the income statement. Effective January 1, 2004, the Trust has recorded revenue gross of transportation system charges and a transportation system charge on the income statement. Prior periods have been reclassified for comparative purposes. This adjustment has no impact on net income or cash flow for the Trust.

4. PETROLEUM AND NATURAL GAS PROPERTIES AND EQUIPMENT

		2004		2003
Petroleum and natural gas properties and equipment, at cost	$	450,493,107	$	291,005,504
Accumulated depletion and depreciation		(148,038,322)		(116,031,197)
Petroleum and natural gas properties and equipment, at cost, net	$	302,454,785	$	174,974,307

The petroleum and natural gas properties and equipment, at cost, and the accumulated depletion and depreciation 2004 balances include $9.8 million and $2.8 million related to the asset retirement obligation, respectively. The 2003 balances have been restated due to the adoption of the asset retirement obligation method of recording the future cost associated with removal, site restoration and asset retirement costs. As a result of this restatement, petroleum and natural gas properties and equipment, at cost, has increased by $6.3 million and accumulated depletion and depreciation has increased by $2.2 million.

The calculation of depletion and depreciation in 2004 included an estimate of $47.5 million (2003 - $28.4 million) for future development costs and $4.1 million (2003 – nil) for future asset retirement costs associated with proved undeveloped reserves. Unproved property costs of $3.1 million (2003 - $1.8 million) and estimated net realizable value of production equipment and facilities of $21.9 million (2003 - $12.6 million) were excluded from the depletion calculation.

The Trust performed a cost impairment test at December 31, 2004 to assess the recoverable amount of the net carrying value of petroleum and natural gas properties and equipment. Future prices for crude oil and natural gas were obtained for the period 2005 to 2009 inclusive from the Trust's year-end independent reserve evaluations and then escalated based on escalation factors in the same evaluations. Based on these assumptions, the present value of future net revenues from the Trust's proved plus probable reserves exceeded the carrying value of the Trust's net carrying value of the petroleum and natural gas properties and equipment.

The future prices used for the cost impairment test for December 31, 2004 are as follows.

Consultant's Price Forecasts	2005	2006	2007	2008	2009
Crude Oil - WTI ($US / bbl)	$ 42.00	$ 40.00	$ 37.50	$ 35.00	$ 33.00
Natural Gas AECO ($CDN / Mmbtu)	$ 6.78	$ 6.52	$ 6.26	$ 6.00	$ 5.73

5. ACQUISITION EXPENDITURES

Area	Effective	Year ended December 31, 2004	Year ended December 31, 2003
Lanaway, Alberta	May 1, 2003	$ (39,885)	$ 4,741,298
Loon Lake, Alberta	June 1, 2003	(103,530)	17,434,118
Tommy Lakes, B.C.	April 1, 2004	110,074,959	–
Medicine Hat, Alberta	September 1, 2004	18,607,466	–
Medicine Hat, Alberta	October 1, 2004	1,144,700	–
Other		15,604	–
		$ 129,699,314	$ 22,175,416

Acquisition of Tommy Lakes Partnership April 1, 2004

On April 1, 2004 the Trust acquired the Tommy Lakes Partnership, which owns interests in the natural gas producing area of Tommy Lakes, British Columbia. The Tommy Lakes Partnership is owned 99 percent by Focus B.C. Trust and one percent by FET Resources Ltd., both of which are wholly owned subsidiaries of Focus Energy Trust. This acquisition was accounted for using the purchase method, with results of operations included from the date of acquisition. The future income tax recorded for this transaction only relates to the one percent ownership by FET Resources Ltd., and no future income tax has been recorded with respect to the interest owned by Focus B.C. Trust.

The following summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of the acquisition.

Petroleum and natural gas properties and equipment	$111,583,959
Asset retirement obligation	(877,109)
Future income tax	(631,891)
	$110,074,959

Acquisition of Private Company September 1, 2004

FET Resources Ltd. acquired a private company on September 1, 2004 for cash consideration of $19,090,000. This acquisition was accounted for using the purchase method, with results of operations included from the date of acquisition. Immediately after the acquisition, the private company was wound up into FET Resources Ltd.

The following summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of the acquisition.

Petroleum and natural gas properties and equipment	$20,190,000
Goodwill	5,100,000
Asset retirement obligation	(1,061,838)
Future income tax	(5,620,696)
	$18,607,466
Net working capital	482,534
	$19,090,000

Effective October 1, 2004, additional interests were purchased in the Medicine Hat area for cash consideration of $1,144,700.

6. ASSET RETIREMENT OBLIGATION

The Trust's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Trust estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately $31.2 million which will be incurred between 2005 and 2020. The majority of the costs will be incurred after 2019. A credit-adjusted risk-free rate of 7.0 percent and an inflation rate of 1.5 percent for estimates prior to the fourth quarter of 2004 and 2.0 percent for revisions and changes thereafter were used to calculate the fair value of the asset retirement obligation.

A reconciliation of the asset retirement obligation is provided below.

		December 31, 2004		December 31, 2003
Balance, beginning of period	$	7,442,069	$	6,001,112
Accretion expense		664,001		420,078
Liabilities incurred				
Acquisitions		1,938,947		961,685
Development activity and change in estimates		1,540,610		79,745
Settlement of liabilities		(124,158)		(20,551)
Balance, end of period	$	11,461,469	$	7,442,069

7. RECLAMATION FUND

		2004		2003
Balance as at January 1	$	1,030,000	$	–
Contributions		892,519		1,030,000
Balance as at December 31	$	1,922,519	$	1,030,000

A reclamation fund was established to fund the payment of environmental and site reclamation costs. Annual contributions will be made to the reclamation fund such that the currently estimated future environmental and site reclamation costs will be funded after 20 years. Interest earned will form part of the reclamation fund. The Company may use the reclamation fund for purposes of funding its environmental and site reclamation costs. The reclamation fund is held on deposit at a Canadian financial institution.

8. LONG-TERM DEBT

The Trust has a $100 million revolving syndicated credit facility among four Canadian financial institutions with an extendible 364-day revolving period and a one-year amortization period. In addition, the Trust has a $10 million demand operating line of credit. At December 31, 2004, the available borrowings under these facilities were reduced by $3.0 million by letters of credit. The credit facilities are secured by a floating charge debenture covering all of the assets of the Trust and a general security agreement.

Advances bear interest at the bank's prime rate, bankers' acceptance rates plus stamping fees, or U.S. LIBOR rates plus applicable margins depending on the form of borrowing by the Trust. Stamping fees and margins vary from zero percent to 1.5 percent dependent upon financial statement ratios and type of borrowing. The effective rate on debt outstanding at December 31, 2004 is approximately 3.6 percent.

The credit facility will revolve until May 26, 2005, whereupon it may be renewed for a further 364-day term subject to review by the lenders. If not extended, principal payments will commence after expiry of the revolving period and will consist of three quarterly payments of five percent and the remaining 85 percent at the end of the term.

9. UNITHOLDERS' CAPITAL AND EXCHANGEABLE SHARES

An unlimited number of Trust Units may be issued pursuant to the Trust Indenture. Each Trust Unit entitles the holder to one vote at any meeting of the Unitholders and represents an equal fractional undivided beneficial interest in any distribution from the Trust and in any net assets in the event of termination or winding up of the Trust. The Trust Units are redeemable at the option of the Unitholder, up to a maximum of $250,000 per annum. This limitation may be waived at the discretion of the Trust.

Trust Units of Focus Energy Trust

(including conversion of Exchangeable Shares)	Number of Units		Consideration	
	2004	2003	2004	2003
Trust Units outstanding (see (a) below)	35,973,651	28,034,233	$ 139,335,147	$ 63,267,421
Trust Units issuable on conversion of Exchangeable Shares[(I)] (see (b) below)	1,249,371	3,788,258	1,546,884	5,160,995
Balance as at December 31	37,223,022	31,822,491	$ 140,882,031	$ 68,428,416

(I) THE EXCHANGE RATIO AT DECEMBER 31, 2004 WAS 1.27833 (DECEMBER 31, 2003 – 1.16718) TRUST UNITS FOR EACH EXCHANGEABLE SHARE.

(a) Trust Units of Focus Energy Trust	Number of Units		Consideration	
	2004	2003	2004	2003
Balance as at January 1	28,034,233	22,804,905	$ 63,267,421	$ 33,908,902
Issued on conversion of Exchangeable Shares[(I)]	2,760,027	3,037,076	3,614,111	4,467,384
Issued pursuant to the Executive Bonus Plan[(II)]	72,391	71,752	1,127,813	841,434
Issued for cash[(III)]		2,100,000		25,410,000
Issued for cash[(IV)]	5,000,000		74,500,000	
Trust Unit issue expenses			(4,080,735)	(1,518,347)
Exercise of Unit Appreciation Rights[(V)]	107,000	20,500	906,537	158,048
Balance as at December 31	35,973,651	28,034,233	$ 139,335,147	$ 63,267,421

(I) ISSUED ON CONVERSION OF EXCHANGEABLE SHARES TO TRUST UNITS WITH THE CONSIDERATION RECORDED BEING EQUAL TO THE BOOK VALUE OF THE EXCHANGEABLE SHARES EXCHANGED

(II) PURSUANT TO THE EXECUTIVE BONUS PLAN, 50 PERCENT OF ALL AMOUNTS DUE UNDER SUCH PLAN ARE PAYABLE THROUGH THE ISSUANCE OF TRUST UNITS PRICED AT THE FIVE-DAY WEIGHTED AVERAGE TRADING PRICE FOR THE LAST FIVE TRADING DAYS OF THE MONTH FOR WHICH THE BONUS RELATES.

(III) ISSUED FOR CASH JUNE 25, 2003 PURSUANT TO A SHORT FORM PROSPECTUS DATED JUNE 17, 2003

(IV) ISSUED FOR CASH MARCH 23, 2004 PURSUANT TO A SHORT FORM PROSPECTUS DATED MARCH 15, 2004

(V) EXERCISE OF UNIT APPRECIATION RIGHTS INCLUDES CASH CONSIDERATION OF $854,040 AND CONTRIBUTED SURPLUS CREDIT OF $52,497.

(b) Exchangeable Shares of FET Resources Ltd.	Number of Shares		Consideration	
	2004	2003	2004	2003
Balance as at January 1	3,245,650	5,964,335	$ 5,160,995	$ 9,628,379
Exchanged for Trust Units[(I)]	(2,268,304)	(2,718,685)	(3,614,111)	(4,467,384)
Balance as at December 31	977,346	3,245,650	$ 1,546,884	$ 5,160,995

(I) CANCELLATION ON CONVERSION TO TRUST UNITS WITH THE CONSIDERATION RECORDED BEING EQUAL TO THE BOOK VALUE OF THE EXCHANGEABLE SHARES EXCHANGED

The Exchangeable Shares of FET Resources Ltd. are convertible at any time into Trust Units (at the option of the holder) based on the exchange ratio. The exchange ratio is increased monthly based on the cash distribution paid on the Trust Units divided by the ten-day weighted average Unit price preceding the record date. During the period of January 1 to December 31, 2004, a total of 2,268,304 Exchangeable Shares were converted into 2,760,027 Trust Units at exchange ratios prevailing at the time. At December 31, 2004, the exchange ratio was 1.27833 Trust Units for each Exchangeable Share. Cash distributions are not paid on the Exchangeable Shares. On the tenth anniversary of the issuance of the Exchangeable Shares, subject to extension of such date by the Board of Directors of the Company, the Exchangeable Shares will be redeemed for Trust Units at a price equal to the value of that number of Trust Units based on the exchange ratio as at the last business day prior to the redemption date. The Company may redeem all but not less than all of the outstanding Exchangeable Shares at any time when the aggregate number of issued and outstanding Exchangeable Shares is less than 1,000,000. The Company will, at least 45 days prior to any redemption date, provide the registered holders with written notice of the prospective redemption. The redemption price is equal to that described previously. The Exchangeable Shares of FET Resources Ltd. are listed for trading on the Toronto Stock Exchange under the symbol FTX.

10. TRUST UNIT RIGHTS PLAN

The Trust Unit Rights Plan (the "Plan") was established August 23, 2002 as part of the Plan of Arrangement. The Trust may grant rights to employees, directors, consultants and other service providers of the Trust and any of its subsidiaries. The Trust is authorized to grant up to 1,500,000 rights, but the number of Units reserved for issuance upon the exercise of rights shall not at any time exceed five percent of the aggregate number of issued and outstanding Units of the Trust and including the number of Units which may be issued on the exchange of the outstanding Exchangeable Shares. To December 31, 2004 a total of 107,000 Units had been issued under the Plan, and 1,393,000 Units are reserved for issuance under the Plan.

The initial exercise price of rights granted under the Plan is equal to the weighted average of the closing price of the Trust Units on the immediately preceding five trading days. The exercise price per right is calculated by deducting from the grant price the aggregate of all distributions, on a per-Unit basis, made by the Trust after the grant date which represents a return of more than 0.833 percent of the Trust's recorded cost of capital assets less depletion, depreciation and amortization charges and any future income tax liability associated with such capital assets at the end of each month. Provided this test is met, then the entire amount of the distribution is deducted from the grant price. The rights have a life of five years and vest equally over a four-year period commencing on the first anniversary of the grant.

	2004		2003	
	Number of Rights	Weighted Average Exercise Price	Number of Rights	Weighted Average Exercise Price
Balance as at January 1, 2004	665,500	$ 9.74	320,000	$ 9.39
Granted	571,150	$ 16.31	376,000	$ 12.19
Exercised	(107,000)	$ 7.42	(20,500)	$ 7.71
Cancelled	(16,550)	$ 14.01	(10,000)	$ 12.08
Before reduction of exercise price	1,113,100	$ 13.27	665,500	$ 11.07
Reduction of exercise price	–	$ (1.49)	–	$ (1.33)
Balance as at December 31, 2004	1,113,100	$ 11.78	665,500	$ 9.74

- The average exercise price at the grant date is $13.74.
- The average contractual life of the rights outstanding is 3.79 years.
- The number of rights exercisable at December 31, 2004 is 123,250.
- The average value at the grant date for the year ended December 31, 2004 is $3.41 ($2.58 for 2003).

The Trust prospectively adopted the fair value method in 2003 for rights granted subsequent to January 1, 2003. The fair value of rights is estimated using a modified Black Scholes option pricing model.

The Trust has recorded non-cash compensation expense of $305,489 for the year ended December 31, 2004. The Trust recorded non-cash compensation expense of $245,524 for the year ended December 31, 2003.

Had the Trust used the fair value method for rights granted between August 23, 2002 and December 31, 2002, pro forma net income would have decreased by $137,133 (2003 - $136,758).

Pro Forma Results		2004		2003
Net income as reported	$	59,628,174	$	41,446,002
Less: Compensation expense for rights issued in 2002		(137,133)		(136,758)
Pro forma net income	$	59,491,041	$	41,309,244
Net income per Trust Unit – basic				
As reported	$	1.66	$	1.36
Pro forma	$	1.66	$	1.36
Net income per Trust Unit – diluted				
As reported	$	1.66	$	1.36
Pro forma	$	1.66	$	1.36

The fair value of rights granted in 2004 was estimated using a modified Black Scholes option pricing model with the following weighted average assumptions: risk-free interest rate of 3.93 percent, volatility of 34 percent, life of 4.8 years and a dividend yield rate of 11 percent. Users are cautioned that the assumptions made are estimates of future events and actual results could differ materially from those estimated.

11. CASH DISTRIBUTIONS PAYABLE

The Trust has net income for each year which includes all interest income from the Company, and other income, which accrues to the Trust to the end of the year. Under the Trust Indenture, taxable income of the Trust for each year will be paid or payable by way of cash distributions to the Unitholders.

The taxable income of the Trust includes a deduction for the allocation of taxable income to Unitholders, which is paid or becomes payable in the year. The Trust Indenture provides that an amount at least equal to the taxable income of the Trust must be paid or payable each year to Unitholders in order to reduce the Trust's taxable income to zero. Such taxable income relating to the payable amount is allocated to Unitholders of record at the end of the year, and each Unitholder receives a pro rata share of the payable amount.

12. FINANCIAL INSTRUMENTS

The Company's financial instruments included in the balance sheet consist of accounts receivable, other receivables, accounts payable and accrued liabilities and bank debt.

Credit risk:
The Company's accounts receivable are due from a diverse group of customers and as such are subject to normal credit risks.

Interest rate risk:
The Company is also exposed to interest rate risk to the extent that long-term debt is at a floating rate of interest.

Fair values:
The fair values of short-term financial instruments, being accounts receivable, accounts payable and accrued liabilities and cash distributions payable approximate their carrying values due to their short term to maturity. The fair value of long-term debt approximates its carrying value due to the floating interest rate and the revolving nature of the obligation.

The following financial contracts were outstanding at the date of writing. The fair market value of the contracts outstanding at December 31, 2004, which have no book value, was a cost of $332,000.

Financial Contracts	Daily Quantity		Contract Price		Price Index	Term
Crude oil – fixed price	400 bbls	$	49.61	Cdn/bbl	WTI	January 2005 – December 2005
	400 bbls	$	49.50	Cdn/bbl	WTI	January 2005 – December 2005
	400 bbls	$	52.00-58.40	Cdn/bbl	WTI	January 2005 – March 2005
	400 bbls	$	52.00-56.15	Cdn/bbl	WTI	April 2005 – June 2005
	400 bbls	$	53.00-60.00	Cdn/bbl	WTI	July 2005 – September 2005*
Natural gas – fixed price	5,000 GJ	$	5.85-6.95	Cdn/GJ	AECO	April 2005 – October 2005*

* CONTRACT ENTERED INTO SUBSEQUENT TO DECEMBER 31, 2004

13. PHYSICAL SALES CONTRACTS

In addition to the financial contracts described above, the following physical contracts were outstanding at the date of writing. The fair market value of these contracts at December 31, 2004, which have no book value, would have resulted in a net payment to the Trust of approximately $7,176,000.

Physical Contracts	Daily Quantity	Contract Price		Term
Natural gas – fixed price				
	26,500 GJ	$ 7.25	Cdn/GJ	November 2004 – March 2005
	5,275 GJ	$ 7.00	Cdn/GJ	November 2004 – October 2005
	5,000 GJ	$ 6.36	Cdn/GJ	April 2005 – October 2005
	7,000 GJ	$ 8.77	Cdn/GJ	January 2005
	15,500 GJ	$ 7.01	Cdn/GJ	April 2005 – October 2005
	7,000 GJ	$ 7.25	Cdn/GJ	November 2005 – March 2006*
	7,000 GJ	$ 7.62	Cdn/GJ	November 2005 – March 2006*

* CONTRACT ENTERED INTO SUBSEQUENT TO DECEMBER 31, 2004

14. PER UNIT AMOUNTS AND SUPPLEMENTARY CASH FLOW INFORMATION

Basic per-Unit calculations are based on the weighted average number of Trust Units. Diluted calculations include additional Trust Units for the dilutive impact of rights outstanding pursuant to the Rights Plan and the number of Trust Units exercisable on conversion of Exchangeable Shares.

Basic per-Unit calculations for the year ending December 31 are based on the weighted average number of Trust Units outstanding in 2004 of 35,903,047 (2003 of 30,493,373).

Diluted calculations include additional Trust Units for the dilutive impact of the Rights Plan and for the weighted average number of Trust Units exercisable on conversion of Exchangeable Shares of 327,465 for the year ended December 31, 2004 (129,990 for the year ended December 31, 2003).

Supplementary cash flow information for the year ended December 31 is as follows.

	2004	2003
Interest paid	$ 1,986,119	$ 1,345,300
Interest received	75,666	18,003
Taxes paid	1,453,298	(862,688)
Cash distributions paid	59,607,831	40,925,594

15. INCOME TAXES

Effective April 1, 2004, the Alberta government enacted a reduction in corporate income tax rates from 12.5 percent to 11.5 percent. In 2003, Royal Assent was received legislating the reduction of the general corporate income tax rate on income from resource activities from 28 percent to 21 percent and for the elimination of the existing 25 percent resource allowance deduction and introduced the deductibility of actual provincial and other Crown royalties paid to be phased in over a five-year period.

The Trust's expected future income tax rate is approximately 35 percent at December 31, 2004 compared to 37 percent at December 31, 2003. The Trust recorded a future income tax recovery of $4.2 million in 2004.

The Trust recognized future income tax liabilities of $6.3 million in 2004 related to the acquisitions of the Tommy Lakes partnership interest and of a private company.

The provision for future income taxes is different from the amount computed by applying the combined statutory Canadian Federal and Provincial income tax rate to income for the period before income taxes. The differences are as follows.

		2004		2003
Income before income and other taxes	$	56,836,734	$	40,815,863
Statutory combined federal and provincial income tax rate		39.40%		40.98%
Expected income tax expense at statutory rates	$	22,396,371	$	16,726,341
Add (deduct) the income tax effect of:				
Non-deductible Crown charges		9,415,168		10,659,788
Resource allowance		(7,977,986)		(9,077,768)
Alberta Royalty Tax Credit		(163,804)		(117,822)
Reduction in corporate tax rate		(2,152,283)		(3,250,000)
Income attributable to the Trust, not subject to income tax		(24,177,995)		(16,259,305)
Capital tax		1,073,342		879,340
Other		(1,204,253)		(190,713)
Income and other taxes	$	(2,791,440)	$	(630,139)

The components of the future tax liability at December 31 are as follows.

		2004		2003
Capital assets in excess of tax value	$	48,849,568	$	48,640,477
Provision for asset retirement obligation		(4,014,953)		(2,743,147)
Non-capital losses		–		(2,662,029)
Other		(1,107,495)		(1,548,768)
Future income taxes	$	43,727,120	$	41,686,533

16. RELATED PARTY TRANSACTIONS

During 2004, the Trust paid $212,600 for legal services (2003 - $97,730) provided by a firm in which a current director is a partner.

17. COMMITMENTS AND CONTINGENCIES

The Trust is involved in litigation and claims arising in the normal course of operations. Management is of the opinion that any resulting settlements would not materially affect the Trust's financial position or reported results in operations.

QUARTERLY INFORMATION

SUMMARY OF QUARTERLY RESULTS

(000s OF DOLLARS, EXCEPT AS INDICATED)	2004 Q4	2004 Q3	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4	2002 Q3[1] 39 Days
FINANCIAL										
Oil and gas revenues, before transportation system changes and royalties[2]	**39,233**	**37,979**	**42,284**	**30,677**	28,088	28,806	31,979	30,494	26,032	9,216
Funds flow from operations	**23,241**	**21,926**	**25,961**	**18,438**	17,129	15,200	16,764	16,715	14,184	4,818
Per Total Unit - basic	**$0.63**	**$0.59**	**$0.70**	**$0.57**	$0.54	$0.48	$0.57	$0.57	$0.49	$0.17
Cash distributions per Trust Unit	**$0.48**	**$0.45**	**$0.45**	**$0.42**	$0.42	$0.42	$0.42	$0.41	$0.33	$0.11
Payout ratio (per-Unit basis)	**77%**	**76%**	**64%**	**74%**	78%	87%	74%	71%	68%	66%
Net income	**15,451**	**13,546**	**17,286**	**13,346**	10,456	10,608	12,449	7,960	8,738	1,422
Per Unit - basic	**$0.42**	**$0.37**	**$0.47**	**$0.41**	$0.33	$0.34	$0.42	$0.27	$0.30	$0.05
Capital expenditures	**11,325**	**1,529**	**857**	**11,445**	4,749	2,796	50	9,214	3,666	481
Acquisition expenditures , net	**1,190**	**18,580**	**109,945**	**(15)**	142	13	20,062	–	605	–
Long-term debt plus working capital	**81,158**	**75,235**	**60,690**	**(39,893)**	23,611	23,650	27,545	38,767	36,534	38,076
Per unit - basic	**$2.18**	**$2.03**	**$1.64**	**$(1.08)**	$0.74	$0.75	$0.87	$1.33	$1.26	$1.33
Times funds flow from operations[3]	**0.9**	**0.9**	**0.6**	**(0.5)**	0.3	0.4	0.4	0.6	0.6	0.8
Total Trust Units - outstanding (000s)	**37,223**	**37,094**	**37,016**	**36,923**	31,822	31,667	31,493	29,180	28,966	28,736
Wtgd average Total Trust Units (000s)	**37,163**	**37,057**	**36,980**	**32,386**	31,759	31,631	29,458	29,106	29,106	28,605
OPERATIONS										
Average daily production										
Crude oil (bbls/d)	**1,903**	**1,932**	**2,027**	**2,122**	2,278	2,336	2,361	2,444	2,469	2,608
NGLs (bbls/d)	**724**	**776**	**703**	**472**	460	508	501	471	464	441
Natural gas (mcf/d)	**43,080**	**44,903**	**50,913**	**31,902**	32,476	33,593	36,815	34,158	32,911	26,101
BOE (@6:1)	**9,807**	**10,191**	**11,215**	**7,911**	8,151	8,443	8,997	8,608	8,419	7,400
Natural gas weighting	**73%**	**73%**	**76%**	**67%**	66%	66%	68%	66%	65%	59%
Average net product prices realized[4]										
Crude oil (CDN$/bbl)	**$41.28**	**$40.79**	**$40.07**	**$39.66**	$37.20	$39.07	$40.64	$45.84	$37.90	$38.83
NGLs (CDN$/bbl)	**$48.48**	**$45.48**	**$39.62**	**$39.59**	$29.66	$34.18	$30.78	$42.59	$35.70	$33.80
Natural gas (CDN$/mcf)	**$6.64**	**$6.01**	**$6.41**	**$6.65**	$5.78	$4.97	$5.60	$5.84	$4.83	$3.89
Netback per BOE										
Revenue[3]	**$40.82**	**$37.72**	**$38.85**	**$39.92**	$35.15	$32.67	$35.32	$38.50	$31.96	$29.41
Royalties, net of ARTC	**(9.36)**	**(9.22)**	**(9.45)**	**(10.20)**	(8.48)	(8.63)	(9.65)	(12.31)	(8.52)	(7.41)
Production expenses	**(3.76)**	**(3.31)**	**(2.52)**	**(3.78)**	(3.70)	(3.51)	(3.04)	(3.36)	(3.05)	(3.19)
Netback per BOE	**$27.71**	**$25.19**	**$26.88**	**$25.94**	$22.97	$20.53	$22.63	$22.83	$20.40	$18.81
Funds flow from operations per BOE	**$25.76**	**$23.39**	**$25.44**	**$25.61**	$22.84	$19.57	$20.48	$21.57	$18.31	$16.70
Wells drilled (gross)	**8**	**5**	**–**	**11**	10	4	–	9	7	–
TRUST UNIT TRADING STATISTICS										
Unit prices (based on daily closing price)										
High	**$21.39**	**$18.50**	**$15.95**	**$15.23**	$15.30	$14.50	$12.85	$11.74	$10.50	$9.10
Low	**$18.08**	**$15.37**	**$14.60**	**$12.90**	$13.25	$11.95	$10.80	$10.05	$8.85	$10.65
Close	**$19.97**	**$18.08**	**$15.50**	**$14.83**	$15.00	$13.46	$12.09	$11.30	$10.15	$10.63
Daily average trading volume	**139,144**	**101,752**	**106,869**	**112,614**	74,437	85,641	81,199	110,116	108,098	160,462

(1) THE ABOVE INFORMATION ONLY INCLUDES OPERATIONS OF FOCUS ENERGY TRUST WHICH COMMENCED OPERATIONS ON AUGUST 23, 2002.
(2) RESTATED AT DECEMBER 31, 2004 TO BREAK OUT THE TRANSPORTATION SYSTEM CHARGES SEPARATELY (INCREASES REVENUE AND RECORDS THIS NEW EXPENSE)
(3) LONG-TERM DEBT PLUS WORKING CAPITAL DIVIDED BY FUNDS FLOW FROM OPERATIONS FOR THE QUARTER ANNUALIZED
(4) REALIZED PRICES ARE NET OF HEDGING SETTLEMENTS AND TRANSPORTATION SYSTEM CHARGES.

SENIOR MANAGEMENT

Derek W. Evans
President and C.E.O.

William D. Ostlund
Vice President, Finance and C.F.O.

Dennis M. Lawrence
Vice President, Engineering

Bryce H. Murdoch
Vice President, Geology

Al S. Pickering
Vice President, Land

David W. Sakal
Vice President, Operations

A. Kim Schoenroth
Controller

Grant A. Zawalsky
Corporate Secretary

DIRECTORS

Matthew J. Brister[3][4][5]
John A. Brussa[3]
Stuart G. Clark[1][2]
Derek W. Evans
James H.McKelvie[2][3]
Gerry A. Romanzin[2][4][5]

(1) CHAIRMAN OF THE BOARD
(2) MEMBER OF THE AUDIT COMMITTEE
(3) MEMBER OF THE COMPENSATION COMMITTEE
(4) MEMBER OF THE RESERVES COMMITTEE
(5) MEMBER OF THE CORPORATE GOVERNANCE COMMITTEE

HEAD OFFICE

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STOCK EXCHANGE LISTING

TSX Listings:
Focus Energy Trust: FET.UN
FET Resources Ltd.: FTX
(Exchangeable Shares)

SOLICITORS

Burnet, Duckworth & Palmer LLP
Calgary, Alberta, Canada

AUDITORS

KPMG LLP
Calgary, Alberta, Canada

BANKERS

Bank Syndicate
Lead Agent: Royal Bank of Canada
Calgary, Alberta

ENGINEERING CONSULTANTS

Paddock Lindstrom & Associates Ltd.
Calgary, Alberta

McDaniel and Associates Consultants Ltd.
Calgary, Alberta

REGISTRAR & TRANSFER AGENT

Valiant Trust Company
Calgary, Alberta

ABBREVIATIONS

api	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Bcf	Billions of cubic feet
Bcfe	Billions of cubic feet equivalent
BOE	Barrels of oil equivalent @ 6:1
BOE/d	Barrels of oil equivalent per day
bbl	Barrel of oil or natural gas liquids
bbls	Barrels of oil or natural gas liquids
bbls/d	Barrels per day
$CDN	Canadian Dollar
GJ	Gigajoules
GJ/d	Gigajoules per day
Mmbtu	Millions of British Thermal Units
Mmbtu/d	Millions of British Thermal Units per day
mbbl	Thousand barrels
mbbls	Thousands of barrels
Mmbbls	Millions of barrels
Mmcfe/d	Millions of cubic feet equivalent per day
MBOE	Thousands of barrels of oil equivalent
MBOE/d	Thousands of barrels of oil equivalent per day
MMBOE	Millions of barrels of oil equivalent
mcf	Thousands of cubic feet
mcf/d	Thousands of cubic feet per day
Mmcf	Millions of cubic feet
Mmcf/d	Millions of cubic feet per day
Mw	Megawatt
Mw/hr	Megawatt per hour
NGL	Natural gas liquid
OPEC	Organization of Petroleum Exporting Countries
RLI	Reserve Life Index
TSX	Toronto Stock Exchange
WTI	West Texas Intermediate
$US	Unites States dollar

FOR FURTHER INFORMATION CONTACT:

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